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EXECUTIVE SUMMARY

Catawba Nuclear Station, Units 1 and 2
NRC Inspection Report 50-413/97-01 and 50-414/97-01

This inspection included a review of the licensee's implementation of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" [the Maintenance Rule]. The report covers a 1-week period of inspection by inspectors from Region II.

Operations

- In general, operators and schedulers interviewed clearly understood the philosophy of the Maintenance Rule and their specific responsibilities for implementation of the Rule. They were familiar with the Maintenance Rule procedures and the Probabilistic Risk Assessment Matrix, but they did not fully understand the risk implications for some plant configurations that were not addressed by the matrix (Section O4.1).

Maintenance

- Required Structures, Systems, or Components (SSC), with the exception of five functions, were included within the scope of the Maintenance Rule. A violation was identified for failure to include all SSCs within the scope of the Maintenance Rule as required by 10 CFR 50.65(b), (Section M1.1).
- The licensee was performing periodic evaluations and assessments that met the requirements of the Maintenance Rule. The health reports and the first "Unit 1 Cycle 9 Periodic Assessment" were considered detailed (Section M1.3).
- The licensee's method of balancing reliability and unavailability provided an acceptable approach, and the completed periodic assessment met the intent of section (a)(3) of the Rule (Section M1.4).
- The licensee considered safety in establishment of goals and monitoring for systems and components reviewed. Also, corrective actions, goals, and monitoring were comprehensive for all the systems and components reviewed, which was considered a strength. An inspector followup item was identified for followup and review of licensee procedure to implement the requirements of (a)(1) and (a)(2) of the Maintenance Rule after issuance of Revision 2 of Regulatory Guide 1.160 (Section M1.6).
- In most cases, appropriate acceptance criteria were established, industry-wide operating experience was considered; where practical, appropriate trending was being performed, and corrective action was taken when Systems, Structures, or Components failed to meet performance criteria, or when a System, Structure, or Component experienced a Maintenance Preventable Functional Failure. An inspector followup item was identified for followup on licensee actions to provide performance

criteria for structures after industry resolution of the issue. A violation was identified for failure to implement the requirements of (a)(1) and (a)(2) of the Maintenance Rule relating to load reduction transients caused by maintenance related problems (Section M1.7).

- Plant material condition and housekeeping observed during walkdowns was generally good. Preservation of equipment by painting was considered to be good. The housekeeping and material condition discrepant items noted were apparently items indicative of lack of attention to detail on the part of operations and maintenance personnel who made frequent tours of the areas (Section M2.1).

- Audits and assessments were detailed and thorough. Audit and assessment concerns and recommendations were addressed in a timely manner. (Section M7.1).

<u>Engineering</u>

- The licensee's approach in performance of risk ranking for the Maintenance Rule was adequate. The licensee's performance criteria for reliability and unavailability appeared to be commensurate with assumptions in the PRA (Section M1.2).

- Weaknesses in the licensee's program for assessing risk when removing equipment for service for maintenance were identified. Examples of weaknesses were: no quantitative assessment was performed for any of the combinations on the matrix; guidance was not provided for assessing true plant risk when three or more matrix functions were affected at the same time; and no procedural restrictions were placed on the number of functions or SSCs that could be removed from service concurrently. Risk was determined to be appropriately estimated for the recent plant configurations reviewed (Section M1.5).

- System Engineers were knowledgeable of the Maintenance Rule and were implementing it in a satisfactory manner (Section E4.1).

Report Details

Summary of Plant Status

Catawba Units 1 and 2 operated at power during the inspection period.

Introduction

The primary focus of this inspection was to verify that the licensee had implemented a maintenance monitoring program which met the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," (the Maintenance Rule). Inspection was performed by a team of inspectors that included a team leader and five Region II-based inspectors. In addition, NRC staff support was provided by one Senior Reactor Analyst from Region II, one Senior Reactor Analyst from the Probabilistic Safety Assessment Branch, Office of Nuclear Reactor Regulation (NRR), and one reactor engineer from the Quality Assurance and Maintenance Branch, NRR. The licensee provided an overview presentation of the program to the team on the first day of the inspection. The overview handout is included as Attachment 1 to this report.

I. OPERATIONS

O4 Operator Knowledge and Performance

O4.1 Operator Knowledge of Maintenance Rule

a. Inspection Scope (62706)

During the inspection, the team interviewed one licensed reactor operator (RO), two non-licensed operators, three licensed senior reactor operators (SROs) and six schedulers to determine if they understood the general requirements of the Maintenance Rule and their particular duties and responsibilities for its implementation.

b. Observations and Findings

The tasks associated with the Maintenance Rule that operators were responsible for included the following:

- Determining the impact on availability of SSCs when tagging equipment out-of-service and performing administrative requirements for tagging.
- Determining SSC out-of-service logging requirements and impact on availability.
- Evaluating priorities for system restoration.
- Evaluating job scheduling activities.

- Evaluating plant configuration to determine if work authorization created undue risk.

In general, the operators interviewed understood the philosophy of the Maintenance Rule and their responsibilities associated with the Rule. The operators all believed that they were adequately trained and understood the requirements of the applicable procedures. All operators understood the need to restore equipment to operating condition and minimize SSC unavailabilities. Also, all indicated the need to document SSC outages in the control room log books for all SSCs under the scope of the Maintenance Rule. This documentation included noting when equipment was taken out of service and when the equipment was returned to service.

The CNS PRA matrix was a tool used by operators and schedulers to assess risk when removing equipment from service. The team noted weaknesses in the procedure governing matrix use and in the construction of the matrix. These weaknesses are addressed in Section M1.5 of this report. Operators and schedulers were interviewed to determine their familiarity with the use of the matrix and for their knowledge of the limitations of the matrix. Those interviewed demonstrated an adequate knowledge of the purpose and use of the CNS PRA Matrix as defined by WPM 607, MAINTENANCE RULE ASSESSMENT OF EQUIPMENT REMOVED FROM SERVICE, Revision 1. However, none of the personnel interviewed were aware that the matrix may not provide an accurate assessment of risk when more than two out-of-service functions were affected. Also, they were not aware that removing items from service that were not on the matrix could have an adverse affect on overall plant risk.

To evaluate the licensee's decision to scope certain communications and lighting systems out of the Rule, operators were interviewed to determine which were used during abnormal situations at the plant. The SROs indicated that except for verbal communications, the primary communications relied upon during an event or emergency situation was telephones. Also, the primary lighting relied upon during the same situations was DC lighting. At the time of the inspection, the ECI system (Interplant Telephones) was not included in the Scope of the Maintenance Rule, and the DC Emergency Lighting was included in the Scope of the Maintenance Rule. The team did note the licensee had included the portable radios in the scope of the Maintenance Rule. The licensee issued a PIP (0-C97-0412) to evaluate the need to include telephones in the Maintenance Rule.

c. <u>Conclusions</u>

In general, the ROs, SROs, non licensed operators, and schedulers interviewed clearly understood the philosophy of the Maintenance Rule and their specific responsibilities for implementation of the Rule. They were familiar with the Maintenance Rule procedures and the CNS PRA Matrix but did not fully understand the risk implications for some plant configurations that were not addressed by the matrix.

II. MAINTENANCE

M1 Conduct of Maintenance

M1.1 Scope of Structures, Systems, and Components Included Within the Rule

a. Inspection Scope (62706)

Prior to the onsite inspection, the team reviewed the Catawba Nuclear Station Final Safety Analysis Report, Licensee Event Reports, the Emergency Operating Procedures, previous NRC Inspection Reports, and other information provided by the licensee. The team selected an independent sample of structures, systems, and components that the team believed should be included within the scope of the rule, which had not been classified as such by the licensee. During the onsite portion of the inspection, the team used this list to determine if the licensee had adequately identified the structures, systems, and components that should be included in the scope of the rule in accordance with 10 CFR 50.65(b).

b. Observations and Findings

The licensee reviewed approximately 583 functions and determined that approximately 344 were in the scope of the Maintenance Rule.

The team reviewed the licensee's database of 239 functions excluded from the Maintenance Rule and selected a sample of 40 excluded functions to verify the appropriateness of the exclusion. The following inappropriate exceptions were identified:

- The licensee had not included the Nuclear Sampling Systems (NM-3 and NM-4), and Auxiliary Building Chilled Water System (YN-1) (maintains chilled water to the NM sample flow Heat exchanger) in the scope of the Maintenance Rule. Further review of these non-safety systems determined that these systems were relied upon to mitigate accidents or transients.

- The licensee had not included the Main Steam to Auxiliary Equipment system SA-3 (maintains steam supply to the three condensate steam air ejectors on each unit) - this non-safety related system was not included in the scope of the Maintenance Rule, even though it could cause a scram or the actuation of a safety-related system ..

- The licensee had not included the Ice Condenser hitch pins (073S) in the scope of the Maintenance Rule. Further review of these components determined that their failure could prevent safety-related structures, systems, and components from fulfilling their safety-related function.

The Regulations, 10 CFR 50.65(b), establish the scoping criteria for selection of safety-related and non-safety related structures, systems, or components to be included within the Maintenance Rule program. Scoping criteria includes non-safety related structures, systems, or components that are relied upon to mitigate accidents or transients, or are used in the plant emergency operating procedures, or whose failure could prevent safety-related structures, systems, and components from fulfilling their safety-related function, or whose failure could cause a reactor scram or the actuation of a safety-related system. The deficiencies concerning scoping discussed above are included as examples of a Violation of these requirements, and were identified as Violation **50-413, 414/97-01-01, (Failure to Include All Structures, Systems, and Components in the Scope of the Maintenance Rule as Required by 10 CFR 50.65(b))**.

The licensee issued a PIP (0-C97-0419) to address the scoping issues.

c. <u>Conclusions</u>

Based on the sample of functions reviewed, required SSCs, with the exception of functions noted above, were included within the scope of the Maintenance Rule. A violation was identified for failure to include all SSCs within the scope of the Maintenance Rule as required by 10 CFR 50.65(b).

M1.2 <u>Safety or Risk Determination</u>

a. <u>Inspection Scope (62706)</u>

Paragraph (a)(1) of the rule requires that goals be commensurate with safety. Implementation of the rule using the guidance contained in NUMARC 93-01 requires that safety be taken into account when setting performance criteria and monitoring under (a)(2) of the rule. This safety consideration would then be used to determine if the SSCs should be monitored at the train or plant level. The team reviewed the methods that the licensee had established for making these required safety determinations. The team also reviewed the safety determinations that were made for the functions that were reviewed in detail during this inspection.

b. <u>Observations and Findings</u>

CNS established the expert panel in accordance with Section 9.3.1 of NUMARC 93-01. The Expert Panel established which functions were within the scope of the rule, the risk significance ranking of SSCs, the performance criteria of SSCs, and the goals for SSCs, (a)(1), and (a)(2) lists. The expert panel membership included representatives from operations, maintenance and engineering. The members had extensive experience. In addition, many panel members were either registered Professional Engineers or were previously licensed Senior Reactor Operators.

The panel determined final risk significance ranking based on a combination of results from a probabilistic risk assessment and deterministic considerations. The CNS PRA provided quantitative measures of risk achievement worth, risk reduction worth, and core damage frequency contribution which were consistent with the guidance provided in NUMARC 93-01. To allow for discussion of all cutsets, high risk cutsets containing human actions were not screened out prior to evaluation by the panel. The expert panel removed nine functions from the list of SSCs which had met at least one of the quantitative criteria. The team reviewed this list and concurred with the expert panel's reasoning. At the time of the inspection, the expert panel had declared 77 functions to be risk significant out of the 583 functions within the scope of the Rule. The team did not identify any functions that had been improperly ranked.

b.1 Risk Ranking

The team reviewed a sample of SSCs covered by the Rule that the expert panel had categorized as non-risk significant to assess if the expert panel had adequately established the safety significance of those SSCs.

The team determined that the licensee had included a consideration of initiating events or select recovery actions in the ranking process.

The licensee's PRA model used was that of the IPE submitted to the NRC, dated August 30, 1991. The model used generic data and plant specific data gathered from 1978 to 1989 as the basis for its availability and reliability data. The data had not been updated for the Maintenance Rule. The cutsets generated from the original model were the basis for evaluations. The model was not rerun or requantified; only a cutset manipulator was used. Application of recovery rules was not automated in the original model. This would lead to very long times required to completely requantify the solution for performing an evaluation.

The team also reviewed the truncation limits used during the risk ranking process. Truncation limits are imposed on PRA models in order to limit the size and complexity of the results to a manageable level. CNS used a truncation level of 1E-8 when quantifying their PRA. This was more than two orders of magnitude less than the overall core damage frequency estimate of 6E-5. This limit was higher than is normally considered desirable to ensure that no risk significant SSCs were omitted from risk ranking considerations. Sensitivity studies had not been conducted by the licensee to determine if 1E-8 would include all significant SSCs. This was considered a weakness by the team. The team determined that a high limit was used because of the licensee's inability to run the PRA model in a reasonable amount of time. Otherwise, it appeared that the licensee's process was adequate to perform the risk ranking for the Maintenance Rule.

Based on this review, it appeared that the licensee's process was adequate to perform the risk ranking for the Maintenance Rule.

b.2 Performance Criteria

The team reviewed the licensee's performance criteria to determine if the licensee had adequately set performance criteria under (a)(2) of the Maintenance Rule consistent with the assumptions used to establish the safety significance. Section 9.3.2 of NUMARC 93-01 recommends that risk significant SSC performance criteria be set to assure that the availability and reliability assumptions used in the risk determining analysis (i.e. PRA) are maintained. CNS elected to use performance criteria that counted maintenance preventable functional failures (MPFFs) at the system level and availability at the function level. The limit on MPFFs was initially set at two per operating cycle for all systems. Availability limits were based on PRA assumptions and varied according to the risk significance of the function. At the time of the inspection, the licensee had reevaluated the assignment of two MPFFs per operating cycle as a generic system reliability performance criteria and was in the final approval stage of updating their criteria. Using the limit of less than two MPFFs per system as a generic reliability performance criteria does not preserve the assumptions of the PRA in all cases. However, for the systems and functions reviewed, the team found that restrictive availability criteria for risk significant functions would compensate for the less restrictive reliability criteria. Specifically, for those functions where an MPFF of one was unacceptable, the licensee had set the required availability to 100%. CNS performed a sensitivity analysis that demonstrated that the use of the unavailability performance criteria would not have had a significant impact on total CDF, (i.e. the use of the Maintenance Rule criteria would have resulted in an approximately 10% increase in CDF if all of the SSCs were assumed to be simultaneously at half of their allowable values and well above their outer limit for CDF at the limit of their allowable value). The team considered the licensee's approach to setting performance criteria acceptable.

b.3 Expert Panel

The team reviewed the licensee's process and procedures for establishment of an expert panel. It was determined that the licensee had established an expert panel in accordance with the guidance provided in NUMARC 93-01. The expert panel's responsibilities included the final authority for decisions regarding maintenance rule scope, risk significance, and performance criteria selection.

Duke Power Procedure EDM-210, REQUIREMENTS FOR MONITORING THE EFFECTIVENESS OF MAINTENANCE OF NUCLEAR POWER PLANTS OR THE MAINTENANCE RULE, Revision 3, contained the guidance regarding expert panel activities, member qualifications and expert panel meeting conduct. The panel was comprised of personnel from the Catawba and McGuire Nuclear Stations as well as personnel from the Duke Power Company General Office.

The expert panel convened a meeting at the NRC's request during the inspection. Panel members were questioned by the team concerning previous decisions and aspects of panel responsibilities. There was a good discussion of the issues and adequate participation from all panel members.

c. Conclusions

Based on the review of the above sampled SSCs, it appeared the licensee's approach in performance of risk ranking for the Maintenance Rule was adequate. The licensee's performance criteria for reliability and unavailability appeared to be commensurate with assumptions in the PRA.

M1.3 Periodic Evaluation

a. Inspection Scope (62706)

Paragraph (a)(3)of the Rule requires that performance and condition monitoring activities and associated goals and preventive maintenance activities be evaluated taking into account, where practical, industry-wide operating experience. This evaluation was required to be performed at least one time during each refueling cycle, not to exceed 24 months between evaluations. The team reviewed the licensee's periodic evaluation for Unit 1.

b. Observations and Findings

At the time of this inspection, the licensee was not required to have completed the first periodic evaluation. However, the licensee had performed their first periodic assessment for Unit 1 and the shared Unit 0 shared equipment from March 22, 1995, through October 4, 1996. This assessment did not address Unit 2 SSCs. The licensee stated there would be a separate Unit 2 Periodic Assessment. In addition, the licensee had previously performed a Historical Assessment over a three year period from January 1, 1993, to December 31, 1995. This Historical Assessment was performed to develop a database and identify the initial (a)(1) systems.

This "First Assessment" contained twelve sections and seven appendices. The sections included 1) Executive Summary, 2) Introduction, 3) Evaluation of Scoping Results, 4) Evaluation of Risk Significance, 5) Evaluation of Performance Criteria, 6) Evaluation of Performance History, 7) Classification of (a)(1)/(a)(2) SSCs, 8) Goal Setting and Monitoring for (a)(1) SSCs, 9) Industry Operating Experience, 10) Evaluation of Equipment Removed From service, 11) Structures Evaluations, 12) Balancing Availability and Reliability.

The appendices included 1) List of Systems in the MR, 2) List of Structures and Components in MR, 3) List of SSCs that are Risk Significant, 4) List of MPFFs and

Repetitive MPFFs, 5) Unavailability Summary, 6) Forced Outage Rate Summary, and 7) MR (a)(1) List. The "Forced Outage Rate" was used instead of "Unplanned Capability Loss Factor" discussed in NUMARC 93-01.

Other periodic assessments performed by the licensee included a monthly "System Health Indicator Report". The monthly Health Report contains complete maintenance rule data for all the systems. There also was a "Quarterly Assessment Report" for each system that identified health measures. The health reports, both monthly and quarterly, were very detailed and contained extensive data to meet the requirements for periodic assessment for the Maintenance Rule. The same type of data listed in the Appendices for the First Assessment was also in the monthly and quarterly health reports.

c. Conclusions

The team concluded that the licensee was performing periodic evaluations and assessments that met the requirements of the Maintenance Rule. The health reports and the first "Unit 1 Cycle 9 Periodic Assessment" were considered detailed.

M1.4 Balancing Reliability and Unavailability

a. Inspection Scope (62706)

Paragraph (a)(3) of the Rule requires that adjustments be made where necessary to assure that the objective of preventing failures through the performance of preventive maintenance is appropriately balanced against the objective of minimizing unavailability due to monitoring or preventive maintenance. The team met with the Maintenance Rule Coordinator, PRA representative, and representatives of the Expert Panel to discuss the licensee's methodology for balancing reliability and unavailability.

b. Observations and Findings

The team reviewed the licensee's approach to balancing system reliability and unavailability for risk significant systems to achieve an optimum condition. The licensee had scheduled balancing reviews during periodic evaluations at refueling outages, not to exceed 24 months. The requirements for balancing reliability and unavailability were discussed in EDM-210, REQUIREMENTS FOR MONITORING THE EFFECTIVENESS OF MAINTENANCE OF NUCLEAR POWER PLANTS OR THE MAINTENANCE RULE, Revision 3. The Maintenance Rule Coordinator was responsible for the balancing process for risk significant systems during periodic system evaluations. The Maintenance Rule Coordinator was also responsible for collecting data from the system engineers, who monitor and trend the system performance continuously.

The licensee's approach to balancing equipment reliability and unavailability consisted of establishing goals and/or performance criteria for the appropriate SSC and function and then monitoring the performance of the affected equipment. An implicit assumption was made that if appropriate goals and criteria were set and if such goals and criteria were met, then an appropriate balance between unavailability and reliability would be achieved.

The team concluded that such an approach should provide a reasonable balance, provided that appropriate goals and performance criteria were always established.

The licensee had conducted an assessment to determine the impact of Catawba Nuclear Station specific experience on the calculated core damage frequency. The team reviewed the assessment titled "PSA Assessment of CNS Unit 1 Cycle 9 Maintenance Rule Experience" Revision 1, dated September 5, 1996. Considered in the analysis was data from operating cycle 9 for Unit 1 for unavailability, functional failures, human errors and plant transients. Reliability calculations included estimated demands when actual data was not available. The results of the analysis indicated a calculated core damage frequency of 3.32E-5/year. This represents a 45% reduction in the core damage risk for the cycle when compared to the Catawba PRA baseline value of 6.0E-5/year. Based on the results of this assessment, the licensee determined that reliability and availability were adequately balanced and that no adjustments were necessary to Maintenance Rule performance criteria. The team concurred with the licensee's assessment.

c. Conclusions for Balancing Reliability and Unavailability

The team concluded that the licensee's method of balancing reliability and unavailability provided an acceptable approach and the completed periodic assessment met the intent of section (a)(3) of the Rule.

M1.5 Plant Safety Assessments Before Taking Equipment Out of Service

a. Inspection Scope (62706)

Paragraph (a)(3) of the Maintenance Rule states that the total impact on plant safety should be taken into account before taking equipment out of service for monitoring or preventive maintenance. The team reviewed the licensee's procedures and discussed the process with the PRA representative, plant operators, shift work managers, discipline schedulers, and Operations Matrix Support personnel.

b. Observations and Findings

The team reviewed the licensee's process and performance regarding their risk assessment for removing equipment from service. The process was documented in the "Work Process Manual: Section 607, MAINTENANCE RULE ASSESSMENT OF EQUIPMENT REMOVED FROM SERVICE" for removing equipment from service while the plant is at power, and in "Catawba Nuclear Site Directive 3.0.10, UNIT SHUTDOWN MANAGEMENT" for use when the plant is shut down.

When the plant is at power, the "CNS PRA Matrix" (Attachment 607.6.8 in WPM 607) was used by planners and work managers to evaluate plant risk for single and double equipment outages. The licensee used a 12-week rolling schedule for planning surveillance and preventive maintenance. The planners stated that they used the risk matrix to prevent planned concurrent equipment outages that would place the plant in a high risk situation. The shift work managers and SROs stated that they used the risk matrix for emergent work (resulting from unanticipated equipment failures). For combinations of equipment outages not covered by the risk matrix, all personnel interviewed stated they used experience and judgment to evaluate plant risk.

The risk matrix in use at the start of the inspection (February 10, 1997) was considered to be weak in terms of its construction and less than effective use of PRA information to evaluate plant risk from concurrent equipment outages. Specific issues were as follows.

- The matrix was constructed by the expert panel using only a qualitative assessment of risk for functions taken out two at a time. There was no quantitative assessment performed for any of the combinations on the matrix. The team considered this a weakness.

- Neither the matrix nor WPM-607 provided guidance for assessing true plant risk when three or more matrix functions were affected at the same time. Such combinations might place the plant in a high risk situation without the user realizing this. The matrix used a rule-of-thumb approach that limited the number of low risk combinations that could exist together, but these had only been evaluated two at a time. The team considered this a weakness.

- There were no procedural restrictions on the number of functions or SSCs that could be removed from service concurrently. Multiple combinations of SSCs removed from service may place the plant in a risk significant configuration. The team considered this a weakness.

The licensee had performed an evaluation of the combinations of equipment taken out-of-service during Unit 1 Cycle 9 to determine if high risk configurations had existed. They determined that no periods of high risk had existed.

In addition to the above, the team noted another area that was not buttressed by procedural guidance and relied heavily on the skills of those implementing the process. There was no guidance for recovery from high risk configurations (no guidance on determining which piece of equipment to return to service first).

The team reviewed the licensee's process for assessing shutdown risk. The licensee's guidance for shutdown risk was contained in Catawba Nuclear Site

Directive 3.0.10, UNIT SHUTDOWN MANAGEMENT, Revision 9, and in Catawba Nuclear Site Directive 3.1.30, UNIT SHUTDOWN CONFIGURATION CONTROL, Revision 7. The team considered the guidance adequate.

c. Conclusion

The team identified weaknesses in the licensee's program for assessing risk when removing equipment for service for maintenance as stated above. Risk was determined to be appropriately estimated for the recent plant configurations reviewed.

M1.6 Goal Setting and Monitoring for (a)(1) SSCs

a. Inspection Scope (62706)

Paragraph (a)(1) of the Rule requires, in part, that licensees shall monitor the performance or condition of SSCs against licensee-established goals, in a manner sufficient to provide reasonable assurance the SSCs are capable of fulfilling their intended functions. The Rule further requires goals to be established commensurate with safety and industry-wide operating experience be taken into account, where practical. Also, when the performance or condition of the SSC does not meet established goals, appropriate corrective action shall be taken.

The team reviewed the systems and components listed below which the licensee had established goals for monitoring of performance to provide reasonable assurance the system or components were capable of fulfilling their intended function. The team verified that industry-wide operating experience was considered, where practical, that appropriate monitoring was being performed, and that corrective action was taken when SSCs failed to meet goal(s) or when a SSC experienced a MPFF.

The team reviewed program documents and records for six systems or components the licensee had placed in the (a)(1) category in order to evaluate this area. The team also discussed the program with the licensee management, the Maintenance Rule Coordinator, system engineers, and other licensee personnel.

b. Observations and Findings

b.1 Nuclear Service Water - System RN

The team verified that the licensee had implemented goal setting and monitoring as required by paragraph (a)(1) of the Maintenance Rule for Nuclear Service Water System (RN). The RN systems for Units 1 and 2 were classified (a)(1) on June 26, 1996. For Unit 1, the risk significant performance criterion of zero repetitive MPFF's was exceeded for the period January 1, 1993, through December 31, 1995. Additionally, Unit 1 unavailability was not confirmed to be less than 2% for the historical review period January 1, 1993, through December 31, 1995.

For Unit 2, the risk significant performance criterion of less than 2 MPFF for the period January 1, 1993, through June 30, 1994, was exceeded and the risk significant performance criterion of zero repetitive MPFF's was exceeded for the period January 1, 1993, through December 31, 1995. Additionally, Unit 2 unavailability was not confirmed to be less that 2% for the historical review period of January 1, 1993, through December 31, 1995.

The MPFF's and repetitive MPFF's resulted from MOV pump and pump discharge check.valve failures. For the MOV problem, the licensee established goals that the RN pump discharge valves will open under all demand conditions and be assured to open against the theoretical maximum delta pressure. For the check valve problem, the licensee established goals that the RN pump discharge check valve will open under all demand conditions, and be validated through inspections and testing to be working properly.

The guidance provided in NUMARC 93-01 specifies that the historical data used to determine the performance of SSCs consist of that data for a period of at least two fuel cycles or 36 months, whichever is less. NUMARC 93-01 also defines "Maintenance" as extending to all supporting functions for the conduct of maintenance activities. The team reviewed PIPs identified against the RN system to determine if MPFF were properly identified in the historical data review. PIPs reviewed were 0-C95-1589, 0-C95-0609, 0-C96-1568, 2-C-96-0141 & 1-C96-2684.

The team noted PIP 0-C95-0609, issued April 20, 1995, identified that both trains of the Control Room Ventilation (VC) and Chilled Water Systems (YC) were inoperable when a valve misalignment occurred during operator restoration from a maintenance activity. The PIP identified this event as a functional failure (FF) and indicated it was not a MPFF because it was considered an Operational Configuration Control error. The team determined this PIP was within the historical data review time-frame, and the operational evolutions were supporting maintenance in that operations was restoring the system back to operating configuration following a maintenance activity.

The team had reviewed Administrative Procedure, EDM-210, REQUIREMENTS FOR MONITORING THE EFFECTIVENESS OF MAINTENANCE AT THE NUCLEAR POWER PLANTS OR THE MAINTENANCE RULE, Revision 3, during preparation for this inspection. They noted the procedure did not provide appropriate guidance to allow the licensee's staff to identify maintenance preventable functional failures associated with operator actions when taking out of service or returning to service systems or components following a maintenance activity.

Procedure EDM-210, Revision 3, paragraph A.2 identified that Operational or Plant Configuration Control events were not MPFFs. The requirements specified in Procedure EDM-210 associated with Operational or Plant Configuration Control events when taking out of service, or returning to service systems or components following a maintenance activity were not in accordance with the NRC definition of maintenance as it related to the Maintenance Rule. Specifically, the procedure did not require identification of maintenance preventable functional failures for these types of operator errors occurring in support of maintenance activities, and resulted in failure to identify a maintenance preventable functional failure during the historical review of the Nuclear Service Water System. This issue was initially identified as a proposed violation during the exit meeting on February 14, 1997.

The team noted the inadequacy in EDM-210 had been identified to licensee personnel prior to the inspection week. However, the licensee took exception to this position during the inspection week and denied the violation at the exit meeting. The licensee provided a position paper (Attachment 2) to support their denial. In addition, the Site Vice President stated at the exit meeting that he considered this violation to be an expansion of the Maintenance Rule requirements by the NRC. The licensee issued a PIP (0-C97-0400) to address this issue.

After the inspection was completed, the team leader discussed the issue and the licensee's position with the NRC headquarters office responsible for the Maintenance Rule. The NRC headquarters office noted that clear guidance would be provided to the industry regarding this issue in Revision 2 to Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, scheduled to be published in a few weeks. This issue will be identified as an inspector followup item **(50-413, 414/97-01-02) for followup and review of licensee procedure to implement the requirements of (a)(1) and (a)(2) of the Maintenance Rule after issuance of Revision 2 of Regulatory Guide 1.160.**

b.2 Control Area Chilled Water - System YC

The licensee's historical review indicated that the YC system had experienced a Repetitive Maintenance Preventable Functional Failures (RMPFF)s resulting from personnel errors during the performance of maintenance. As a result of these failures, the licensee had put the YC system in the Maintenance Rule (a)(1) category. Subsequently through monitoring, the licensee determined that the goal had been met and they returned the YC system to (a)(2) status. The team reviewed the corrective action for these failures, and the goals and monitoring under the (a)(1) status, and concluded that the corrective action, goals, and monitoring were appropriate. The team also reviewed additional work order data concerning performance of this system for the period January 1995 to the beginning of the inspection.

b.3 Control Room Ventilation - System VC

The licensee had experienced a MPFF related to the failure of filter unit charcoal to meet the Technical Specification (TS) required methyl iodine penetration test. The first failure was on Fuel Pool Ventilation (VF) system filter unit and the second was associated with the VC system. As a result of these failures the licensee had put the VC system in the Maintenance Rule (a)(1) category. Subsequently, a failure was identified with a filter unit in the Auxiliary Building Ventilation (VA) system and the licensee had put the VA system in the Maintenance Rule (a)(1) category also. The licensee did not put the original MPFF system VF into the Maintenance Rule (a)(1) category.

The licensee determined that the root cause of the filter charcoal failing to meet the TS required methyl iodine penetration test, was an ineffective sampling technique. The licensee revised their sampling procedure and established goals and a monitoring program for all plant filter units. The team considered licensee's action of only formally putting two systems in the Maintenance Rule (a)(1) category, rather than declaring all the filter units to be in the Maintenance Rule (a)(1) category, to be inappropriate. However, the team noted that the licensee's informal actions of establishing goals and a monitoring program for all the filters were a *de facto* (a)(1) category for all the filters. The licensee issued a PIP (0-C97-0414) to address this issue.

The team reviewed the corrective action for these failures and the goals and monitoring under the (a)(1) status, and concluded that the corrective action, goals and monitoring were appropriate. The team also reviewed additional work order data concerning performance of this system for the period January 1995 to the beginning of the inspection.

b.4 <u>Residual Heat Removal - System ND (Unit 1)</u>

The licensee's historical review indicated that the Unit 1 ND system had violated the Maintenance Rule Performance Criteria of two MPFFs per fuel cycle. These failures placed the system in the Maintenance Rule's (a)(1) category. Both incidents were documented in PIPs 1-C95-2287 and 1-C96-2419 respectively. In the first incident, cap screws used to secure the yoke to the body of valve 1ND-25A were found loose. In the second incident, an improperly installed starter contactor kit prevented valve 1ND-001B from stroking on demand. The team reviewed the corrective actions for these failures, the corresponding root cause analysis, the goals and monitoring under the (a)(1) status. The team concluded that the corrective actions, goals and monitoring of this system were appropriate.

b.5 <u>Containment Penetration Valve Injection Water - System NW (Unit 2)</u>

The licensee's historical review indicated that the Unit 2 NW system had been classified as (a)(1) for the Maintenance Rule as a result of failing the RMPFF performance criterion. These MPFFs were attributed to the failure of certain solenoid valves to respond on demand or failure to stroke within the required time limit during testing. Other RMPFFs were due to a failure to obtain adequate flow rates during execution of a system flush procedure. The aforementioned problems were identified in PIP 2-C96-1507. As such, the team reviewed results of the investigation, evaluation, corrective actions, goals and monitoring under (a)(1) status. Through these reviews and discussions with the cognizant system engineer, the team ascertained that the failure of the valve to stroke on demand was the result of a return spring failure due to hydrogen embrittlement and disk binding due to raw water intrusion. The corrective actions included: installation of replacement valves with hydrogen embrittlement resistant springs, installation of new vernier reed switches to provide for better repeatability during setup, replacement of carbon steel piping with stainless steel material and a change to flush pipe between the RN and NW systems monthly basis to ensure that the lines were kept free from obstructions. Also, by review of documentation and through discussions with the cognizant system engineer, the team ascertained that the subject system had been removed from the list of risk significant systems based on PRA review. The PRA review examined all systems that penetrated containment and applied certain screening criteria to determine if there was a significant potential for the NW system to become a containment isolation failure. This review revealed that NW did not provide sealing water for any of the isolation pathways considered as potential isolation failure paths. The review concluded that since all of the valves which receive NW sealing water were screened out as potential isolation failures, the NW system should not be considered a risk significant system. However, the system engineer indicated that he would continue to monitor and trend the valves for system health purposes. Since replacement of the problem valves, there has been a marked improvement in performance. No functional failures have occurred over the past year and the system engineer indicated that the system was an (a)(2) candidate.

b.6 Main Steam System - SM (Unit 2)

The SM system for Unit 2 was classified as (a)(1) in Historical Assessment Period #2 from July 1, 1994, through December 31, 1995. The Plant Level Performance Criteria of less than two Reactor Trips for Unit 2 was exceeded. The first Unit 2 reactor trip event was related to the Feedwater (CF) system as documented in PIP 2-C94-0993. The second Unit 2 reactor trip event was caused by the SM system and documented in PIP 2-C95-0246. PIP 2-C96-1491 documented the two Unit 2 reactor trip events as a basis for placing the Unit 2 SM system in the (a)(1) classification.

PIP 2-C95-0246 described the Unit 2 reactor trip event of February 22, 1995, that took place as the result of the inadvertent closing of "B" Steam Generator Main Steam Isolation Valve (S/G MSIV 2SM-5). The root cause was identified as the failure of an electrolytic capacitor on the Optical Isolator Card 2MSID6 used for control of the MSIV. The corrective action implemented for Unit 2 was the replacement of all DC optical isolator cards used in control circuits for all systems. The new cards had tantalum capacitors with a life expectancy of approximately 20 years. This life expectancy was much greater than the life of electrolytic capacitors. PIP 2-C96-0446 documented the modification (change out) of the optical isolator cards. Sixty-eight optical isolator cards were changed out in Unit 2 including the cards in the SM system.

The "Goals" for returning the Unit 2 SM system to the (a)(2) classification were to: 1) replace the DC optical isolator cards having electrolytic capacitors with cards that have tantalum capacitors (this was completed) and 2) implement a 12 year preventive maintenance program for change out of the DC optical isolator cards that have a control function (this was in the approval cycle).

c. Conclusions

The licensee considered safety in establishment of goals and monitoring for systems and components reviewed. Also, corrective actions, goals, and monitoring were comprehensive for all the SSCs reviewed, which was considered a strength. An inspector followup item was identified for followup and review of licensee procedure to implement the requirements of (a)(1) and (a)(2) of the Maintenance Rule after issuance of Revision 2 of Regulatory Guide 1.160.

M1.7 Preventative Maintenance and Trending for (a)(2) SSCs

a. Inspection Scope (62706)

Paragraph (a)(2) of the Rule states that monitoring as required in paragraph (a)(1) is not required where it has been demonstrated that the performance or condition of a SSC is being effectively controlled through the performance of appropriate preventive maintenance, such that the SSC remains capable of performing its intended function.

The team reviewed selected SSCs listed below for which the licensee had established performance criteria, and was trending performance to verify that appropriate preventive maintenance was being performed, such that the SSCs remain capable of performing their intended function. The team verified that industry-wide operating experience was considered, where practical, that appropriate trending was being performed, that safety was considered when performance criteria was established, and that corrective action was taken when SSCs failed to meet performance criteria, or when a SSC experienced a MPFF.

The team reviewed program documents and records for selected SSCs the licensee had placed in the (a)(2) category in order to evaluate this area. The team also discussed the program with the licensee management, the maintenance rule coordinator, system engineers, and other licensee personnel.

b. Observations and Findings

b.1 Structures

Based on interviews with the licensee's civil engineer, the team determined the licensee had not started the baseline structural inspections of required structures in the Maintenance Rule scoping document. The baseline inspections were scheduled to commence March 1997, and be complete within 18 months. Periodic surveys will then be performed throughout the life of the plant. The inspection attributes used in the walkdowns for baseline inspections and the periodic surveys of structures were based on applicable design criteria. Photographs were planned to be taken of the findings in order that comparisons could be made of conditions during subsequent inspections.

The team reviewed Procedure EDM-410, INSPECTION PROGRAM FOR CIVIL ENGINEERING STRUCTURES AND COMPONENTS, Revision 0, to evaluate the adequacy of the acceptance criteria and performance criteria planned for evaluation of structural elements such as concrete and structural steels. The team found the acceptance criteria adequate and consistent with design requirements.

The inspector toured the Diesel Generator Building in order to observe the condition of the concrete and steel structures located within and outside the building. Although some minor surface cracking in the concrete walls was observed, the inspector concluded from the visual observations that the building appeared structurally sound. No unacceptable conditions were noted. The licensee recently identified roof leakage in the Diesel Generator Building and had appropriately identified the deficiency as an MPFF. Further, the licensee had scheduled roof repairs in the Spring of 1997. During the walkthrough inspection, the inspector was accompanied by a civil engineer who was knowledgeable and qualified to perform structural evaluations.

The team determined that the licensees performance criterion was any unacceptable structure or structural components that were not capable of performing their intended function, including the protection or support of nuclear safety-related systems or components. Failure of the criterion would constitute a functional failure and could move the structure or component from the (a)(2) to (a)(1) category. The issue of performance criteria for (a)(2) structures is an industry wide problem and has been identified before by NRC. The NRC will work with the industry to provide guidance in this area. An Inspector Followup Item was identified **50-413, 414/97-01-03 (Followup on Licensee Actions to Provide Performance Criteria for Structures After Resolution of this Issue).**

b.2 Component Cooling - System KC

Review of the KC system determined that appropriate performance criteria had been established and monitoring was being accomplished against those criteria. Review of the problems associated with the system determined that appropriate corrective actions had been taken for failures. Operating experience was being used in system monitoring. No deficiencies were noted concerning this system.

b.3 Emergency Diesel Generator - EDG

The team verified that the licensee had implemented appropriate performance criteria, monitoring, and trending. A review of the System Health Indicator Report disclosed that the system had been on an improving trend over the last quarter of 1996. The system was presently rated green. A self-initiated technical audit was conducted to asses the operational readiness and functionality of the Catawba EDG and supporting systems. This audit was performed between March 4 and April 18, 1996. The inspectors reviewed the subject audit report, SA-96-01(C)(SETA)(D/G), and noted that none of the audit findings had a direct impact on the operability or reliability of the EDGs. The audit identified certain weaknesses in some maintenance and operational procedures. These included failure to implement vendor recommendations in maintenance, operation, and trending, inadequate corrective actions and root cause determinations and, certain maintenance deficiencies. To address these audit findings, the licensee initiated a recovery plan which had been completed at the time of this inspection. No operability concerns were identified. Efforts continued in the maintenance area to ensure that proper equipment and training were being provided. The amended TS which was implemented in November 1996, helped reduce the number of engine runs. Also slow starting and slow loading is now permitted by Technical Specification. All of these items have helped to improve EDG reliability. The system engineer was knowledgeable and proactive in the development and implementation of corrective actions. Also, he had actively participated in establishing performance criteria and goals for the EDG.

In addition, the team determined that the licensee had adequately addressed 10 CFR 50.63, Station Blackout Rule Requirements and that these requirements had been incorporated into the EDG performance criteria. The licensee had committed to target EDG availability at 95%, which was used as a basis for EDG reliability under the Maintenance Rule. The target for EDG demands was also incorporated into the EDG performance criteria.

b.4 Rod Control System/Reactor Trip Breakers - IRE

The IRE system was classified as a risk significant (a)(2) system. A review of the system's "Quarterly Assessment Report from October 1, 1996, - December 31, 1996" listed the systems health as good in the following areas: 1) rod drop times, 2) CRDMs zero failure rate, 3) no power supply failures, 4) no circuit card failures, 5) MPFFS and RMPFFS still trend zero, and 6) work orders were low. One area not identified as "good" was that seven PIPs were generated during the quarter.

The current issues with IRE were six group step demand counter failures occurred during the quarter. The apparent root cause was poor quality liquid crystal displays. The "stationary gripper" latching time was being trended. A goal was to be established during the first quarter of 1997 to determine its trending frequency. No problems were identified with the trip breakers.

The performance criteria for the IRE system has an Availability Limit of 100% for the IRE.1 system function of "Rx Trip BKR/Rod Drop Function". This function required "the breakers must open and the rods must drop" during reactor trip events.

The team concluded the IRE system Quarterly Assessment Report had complete system data trended and the report was considered quite good. The IRE system was maintained in such a manner that it was appropriately classified as an (a)(2) system.

b.5 24kV Main Power - EPA

The Main Power System (EPA) consisted of the components in the 22kV isolated phase bus system except for the associated protective relays (instrumentation). The protective relays for the Main Power System were listed in the ERD system. The EPA system included the two 22/230kV main transformers, the associated 6.9/22kV and 13.6/22kV auxiliary transformers, the two generator output breakers, and the 22kV isolated phase bus system. (The Main Power system operates in the 22kV range.) The EPA system had two zones (trains). Each zone had one 22/230kV main power transformer capable of providing approximately 55% output power to the switchyard.

Initially, for design and construction purposes, the 22kV isolated phase bus system was separated in two systems, EPA and ERD. The licensee stated that since the EPA and the ERD systems were not risk significant, they were not combined into one Maintenance Rule system. However, the components in both EPA and ERD are interrelated and part of the same operating system and function as one system.

The EPA health report, "Quarterly Assessment Report 3rd Qtr 1996", stated that the system for each unit was in good health overall and that all goals and performance criteria were met by each being below the set limits. This included the goals for the following: 1) work requests, 2) PIPs (deficiencies reports), 3) dead bus hours, 4) main step-up transformers, and 5) generator power circuit breakers. The current issues with EPA included the planning for a complete bus inspection, 100% gasket replacement and sealing, 100% insulator inspection, and implementation of an upgraded PM and trending template for the Unit 2 outage 2E0C8. One EPA system goal set and trended by the system engineer was 655 Dead Bus Hours maximum per unit. The Dead Bus Hours were not part of the Maintenance Rule plant level performance criteria for the EPA system. The trending of EPA system Dead Bus Hours was a alternate method used by the system engineer to monitor "power reduction" since the Plant Level Performance Criteria of "Forced Outage Rate" did not monitor for power reduction.

Several events had occurred, where a failure in one of the two EPA zones (trains) or associated relaying, had resulted in power reduction. These events were documented in the following PIPs:

- PIP 1-C96-2880, Unit 1, Power reduced to 50%, October 27, 1996

  PIP 1-C96-2880 described a required manual runback to 50% power when an oil leak occurred in Main Transformer 1A. Zone (train) 1A was removed from operation as the result of an oil line failure. A transformer cooling fan vibration caused a weld on the oil return line to crack. This was not identified as a

Functional Failure (FF). The PIP stated that it was not a Maintenance Preventable Functional Failure (MPFF) since the applicable function EPA.2, "Maintains generated power to the switchyard..." was not lost. Power was still being maintained (at a reduced rate) through B Zone (train). The licensee had not established performance criterion for a 50% power (load) reduction.

- PIP 2-C94-0077, Unit 2, Power runback to 56% January 1, 1994

  PIP 2-C94-0077 described a turbine power runback to 56% power that was attributed to a degraded microswitch on Generator 2A side of Motor Operated Disconnect switch (2AG MOD). Initial inspection of the 2AG MOD found the microswitch was corroded and burned. A significant amount of corrosion had formed on the contacts that resulted in arcing and caused a false signal. This false signal caused Generator Breaker 2A to trip open. The licensee had not established performance criterion for a 44% power (load) reduction.

- PIP 2-C94-0999, Unit 2, Power runback to 56% July 13, 1994

  PIP 2-C94-0999 described a power runback from 100% to 56% that was caused by a tripped 2A Main Generator Breaker (PCB). The PCB trip was caused by actuation of protective relays 61-1 and 61-2. It was discovered that relay 61-1 had failed and that relay 61-2 apparently actuated spuriously. No other protective relay actuated or could have caused the trip. However, the licensee did identify this as a functional failure of the relay and tripped breaker, but not an MPFF. The licensee had not established performance criterion for a 44% power (load) reduction.

- PIP 2-C96-1059, Unit 2, Power runback to 50% May 6, 1996

  PIP 2-C96-1059 described a power runback to 50% power when Main Generator Breaker 2B opened. The cause was identified as the pickup of relay XC in 2EB1 when Breaker 8-13 was operated for the emergency power supply to the group 2 cooling bank on 2B MSU. Relay XC, when picked up, provided a direct trip signal to Breaker 2B. This was identified as a functional failure, but not a MPFF. The licensee had not established performance criterion for a 50% power (load) reduction.

The team reviewed Administrative Procedure, EDM-210, REQUIREMENTS FOR MONITORING THE EFFECTIVENESS OF MAINTENANCE AT THE NUCLEAR POWER PLANTS OR THE MAINTENANCE RULE, Revision 3. The team noted that the procedure did not provide plant or system level performance criteria associated with load reductions. Of specific concern was the four power reductions discussed above. The team noted that significant transients (load reductions) occurred as the result of maintenance related problems. However, based on the licensee's function definition for this system, both trains (zones) of the system must fail in order to identify a Maintenance Rule related functional failure. The team noted that no MPFFs were identified, nor would be identified unless both trains (zones) of the EPA System experienced problems at the same time. In theory, one train (zone) could have multiple maintenance rėlated failures resulting in power reduction transients; yet no performance criteria relating to load reductions was established to cause the system to be considered for the (a)(1) category.

Procedure EDM-210, Revision 3, Appendix D, 210. SELECTION OF PERFORMANCE CRITERIA, Section D.2, Plant Level Performance Criteria, specified that "Forced-Outage Rate" of no less than 8% per duty cycle was the plant level performance criteria for loss of power. However, no specific performance criterion was specified when a failure occurred that resulted in a "reduction in power" as discussed in the PIPs above.

The team evaluated the licensee's performance criteria with Maintenance Rule requirements and determined that as of February 10, 1997, the licensee was not monitoring the performance or condition of structures, systems, or components, against licensee-established goals, and/or demonstrating that the performance or condition of a structure, system or component was being effectively controlled through the performance of appropriate preventive maintenance, in a manner sufficient to provide reasonable assurance that such structures, systems, or components, within the scope of the Maintenance Rule, are capable of fulfilling their intended function, in that:

Procedure EDM-210 did not provide adequate performance criteria at the plant or system level relating to load reductions. Four examples were identified where load reductions of approximately 50% were initiated due to maintenance related issues; however, no performance criteria existed to identify maintenance preventable functional failures for these load reductions. The lack of adequate performance criteria relating to load reductions was identified as Violation **(50-413, 414/97-01-04), Failure to implement the requirements of (a)(1) and (a)(2) of the Maintenance Rule relating to load reduction transients caused by maintenance related problems**. The licensee issued a PIP (0-C97-0401) to address this issue.

At the conclusion of the NRC exit meeting on February 14, 1997, licensee senior management informed the Acting Division of Reactor Safety Deputy Director that they disagreed with the proposed violation. The licensee indicated that they would be providing additional information to the team leader on March 5, 1997. The additional information is included as Attachment 3 to this report.

The team subsequently reviewed the licensee's position as indicated in Attachment 3, and determined that no new information was provided relating to the violation.

c. Conclusions

The team concluded that in most cases, appropriate acceptance criteria were established; industry-wide operating experience was considered, where practical, appropriate trending was being performed, and corrective action was taken when SSCs failed to meet performance criteria or when a SSC experienced a MPFF. An inspector followup item was identified for followup on licensee actions to provide performance criteria for structures after industry resolution of the issue. A violation was identified for failure to implement the requirements of (a)(1) and (a)(2) of the Maintenance Rule relating to load reduction transients caused by maintenance related problems.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Material Condition Walkdowns

a. Inspection Scope (62706)

During the course of the reviews, the team performed walkdowns of selected portions of the following systems and plant areas, and observed the material condition of these SSCs.

- Emergency Diesel Generator Building
- Nuclear Service Water System (RN)
- Control Room Ventilation (VC).
- Control Area Chilled Water (YC)
- Component Cooling (KC)
- EDG Rooms Units 1&2
- RHR Pump Rooms Units 1&2 (ND)
- Containment Penetration Valve Injection Water System Unit 1&2 (NW)
- Main Steam (SM)
- Rod Control/Reactor Trip Breakers (IRE)
- 24kV Main Power (EPA)
- Unit 1 Turbine Building

b. Observations and Findings

Housekeeping in the general areas around equipment was adequate. Piping and components were painted, and very few indications of corrosion, oil leaks, or water leaks were evident. The team observed the inside of selected panels and cabinets, and no loose debris, damage, or degraded equipment were noted. Exceptions to good housekeeping included, the 1B RHR/ND pump room where the team observed evidence of white paint smeared on the pump bowl, associated equipment and piping. In addition, the team noted that valve ND-122 was leaking as evidenced by accumulation of water, boric acid crystal buildup on the associated piping below, on the valve and on the floor. The system engineer reported this condition to maintenance who initiated work order, NO.96009420 for corrective action. Also, the system engineer initiated PIP 1-C97-0391 to evaluate the problem as it appeared that the valve had been leaking long enough for someone to have identified and corrected it prior to this time.

During the walkdown inspection of the Control Room Ventilation (VC) and Control Area Chilled Water (YC) rooms, the team noted the following conditions:

- several flexible conduits were not properly captured in their case nipples;
- there were a number of fasteners missing/loose on the guards and covers;
- missing pipe cap on 1RN241;
- improper storage of materials and test fittings, and
- pneumatic fittings in 2CRA-CP-1 had not been properly abandoned.

The licensee issued PIP 0-C97-0399 to address these items.

c. Conclusions

Plant material condition and housekeeping observed during walkdowns were generally good. Preservation of equipment by painting was considered to be good. The housekeeping and material condition discrepant items noted were apparently items indicative of lack of attention to detail on the part of operations and maintenance personnel who made frequent tours of the areas.

M7 Quality Assurance in Maintenance Activities

M7.1 Licensee Self-Assessment

a. Inspection Scope (62706)

The team reviewed licensee's self-assessments to determine if Maintenance Rule independent evaluations were conducted and the findings of the audits were addressed.

b. Observations and Findings

The team reviewed three self-assessment reports:

- NEI assist team assessment conducted on March 13, 1995, through March 17, 1995 for all three Duke nuclear sites;

- Duke Power Performance Assessment Group assessment conducted May 20 through June 6, 1996; and
- Assessment SA-97-45 conducted from February 20-24, 1997, to assess the overall effectiveness of the implementation of the Maintenance Rule requirements at Catawba Nuclear Station.

The overall quality of the audits was good. The audits were detailed, and addressed the Maintenance Rule and several recommendations were listed. The team noted the most significant finding of the above referenced assessments was the fact System Engineers were not familiar with the implementation requirements of the Maintenance rule and did not understand the terminology of the Maintenance Rule. Assessment corrective actions included significant training to all affected System Engineers. During the teams onsite review, interviews with the various System Engineers confirmed the licensee had taken adequate corrective actions to this finding in that all System Engineers interviewed clearly understood the Maintenance Rule requirements. This was considered a strength.

c. Conclusions

The team concluded the audits and assessments were detailed and thorough. The concerns and recommendations were addressed in a timely manner. Corrective actions to the assessment findings were completed or in progress.

III. ENGINEERING

E2 Engineering Support of Facilities and Equipment

E2.1 Review of Updated Final Safety Analysis Report (UFSAR) Commitments (62706)

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special, focused review that compares plant practices, procedures and parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the team reviewed the applicable portions of the UFSAR that related to the areas inspected. The teams verified that the UFSAR wording was consistent with the observed plant practices, procedures and parameters.

E4 Engineering Staff Knowledge and Performance

E4.1 Engineer Knowledge of the Maintenance Rule

a. Inspection Scope (62706)

The team interviewed licensee system owners (System Engineers) for the structures, systems, and components reviewed in paragraphs M1.6 and M1.7 to assess their understanding of the Maintenance Rule and associated responsibilities.

b. Observations and Findings

The team verified that each System Engineer was implementing the Maintenance Rule and the licensee's MR procedures in a satisfactory manner. Each engineer had a Maintenance Rule system book that contained complete system data including trending charts.

c. Conclusions

The team concluded the System Engineers were knowledgeable of the Maintenance Rule and were implementing it in a satisfactory manner.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

The team leader discussed the progress of the inspection with licensee representatives on a daily basis and presented the results to members of licensee management and staff at the conclusion of the inspection on February 14, 1997. The licensee acknowledged the findings presented, with exceptions. A proposed violation was identified for failure to identify a maintenance preventable functional failure associated with an operator error occurring in support of maintenance activities which caused a loss of function of the Nuclear Service Water System. The licensee took exception to this position during the inspection week and denied the violation at the exit meeting. The licensee provided a position paper (Attachment 2) to support their denial. In addition, the Site Vice President stated at the exit meeting that he considered the proposed violation to be an expansion of the Maintenance Rule requirements by the NRC.

The team leader asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

At the conclusion of the NRC exit on February 14, 1997, licensee senior management informed the Acting Division of Reactor Safety Deputy Director that they disagreed with the proposed violation associated with inadequate performance criteria for load reduction transients. They indicated they would be providing additional information relating to this issue at a later date.

PARTIAL LIST OF PERSONS CONTACTED

LICENSEE:

M. Birch, Safety Assurance Manager
B. Felker, Maintenance Rule Coordinator
J. Forbes, Engineering Manager
W. McCullum, Site Vice President
C. Muse, Scheduling Manager
G. Peterson, Station Manager
Z. Taylor, Regulatory Audits

NRC:

P. Balmain, Resident Inspector
D. Collins, Deputy Director, DRS
R. Freudenberger, Senior Resident Inspector
R. Franovich, Resident Inspector

LIST OF INSPECTION PROCEDURES USED

IP 62706 Maintenance Rule

LIST OF ITEMS OPENED

50-413, 414/97-01-01	VIO	Failure to Include All Structures, Systems, and Components in the Scope of the Maintenance Rule as Required by 10 CFR 50.65(b) (Section M1.1).
50-413, 414/97-01-02	IFI	Followup and review of licensee procedure to implement the requirements of (a)(1) and (a)(2) of the Maintenance Rule after issuance of Revision 2 of Regulatory Guide 1.160) (Section M1.6).
50-413, 414/97-01-03	IFI	Followup on Licensee Actions to Provide Performance Criteria for Structures After Resolution of this Issue (Section M1.7).
50-413, 414/97-01-04	VIO	Failure to implement the requirements of (a)(1) and (a)(2) of the Maintenance Rule (Section M1.7).

LIST OF ACRONYMS USED

CF - Main Feedwater System
CDF - Core Damage Frequency
CFR - Code of Federal Regulations

CNS	-	Catawba Nuclear Station
CRDM	-	Control Rod Drive Mechanism
ECI	-	Interplant Telephones
EDG	-	Emergency Diesel Generator
EDM	-	Engineering Directives Manual
EPA	-	Main Power System
IFI	-	Inspector Followup Item
IPE	-	Individual Plant Examination
KC	-	Component Cooling
kV	-	Kilovolt
MOV	-	Motor Operated Valve
MPFF	-	Maintenance Preventable Functional Failure
MSIV	-	Main Steam Isolation Valve
NEI	-	Nuclear Energy Institute
NM	-	Nuclear Sampling
NPF	-	Nuclear Power Facility
NRC	-	Nuclear Regulatory Commission
NRR	-	Office of Nuclear Reactor Regulation
NUMARC	-	Nuclear Management and Resources Council, Inc.
PDR	-	Public Document Room
P.E.	-	Professional Engineer
PIP	-	Problem Investigation Process
PM	-	Preventative Maintenance
PRA	-	Probabilistic Risk Assessment
RAW	-	Risk Achievement Worth
RHR	-	Residual Heat Removal
RMPFF	-	Repetative Maintenance Preventable Functional Failures
RN	-	Nuclear Service Water
RO	-	Reactor Operator
SM	-	Main Steam
SRO	-	Senior Reactor Operator
SSC	-	Structure, System, or Component
TS	-	Technical Specification
UFSAR	-	Updated Final Safety Analysis Report
VA	-	Auxiliary Building Ventilation
VC	-	Control Room Ventilation
VF	-	Fuel Pool Ventilation
VIO	-	Violation
WPM	-	Work Process Manual
YC	-	Control Area Chilled Water
YN	-	Auxiliary Building Chilled Water

LIST OF PROCEDURES REVIEWED

Nuclear System Directive: 310. REQUIREMENTS FOR THE MAINTENANCE RULE, Revision 1.

EDM-210: REQUIREMENTS FOR MONITORING THE EFFECTIVENESS OF MAINTENANCE AT THE NUCLEAR POWER PLANTS OR THE MAINTENANCE RULE, Revision 3.

EDM-410: INSPECTION PROGRAM FOR CIVIL ENGINEERING STRUCTURES AND COMPONENTS, Revision 0.

Work Process Manual: Section 601, INNAGE MANAGEMENT, Revision 4.

Work Process Manual: Section 607, MAINTENANCE RULE ASSESSMENT OF EQUIPMENT REMOVED FROM SERVICE, Revision 1.

3.1.30, UNIT SHUTDOWN CONFIGURATION CONTROL, REVISION 7.

Catawba Nuclear Site Directive 3.0.10, UNIT SHUTDOWN MANAGEMENT, REVISION 9.

ATTACHMENT 1

Catawba

"World Class Nuclear Power"

NRC Maintenance Rule Baseline Inspection

February 10, 1997

WELCOME

Bill McCollum,

Site Vice President

Mary Birch

Safety Assurance Manager

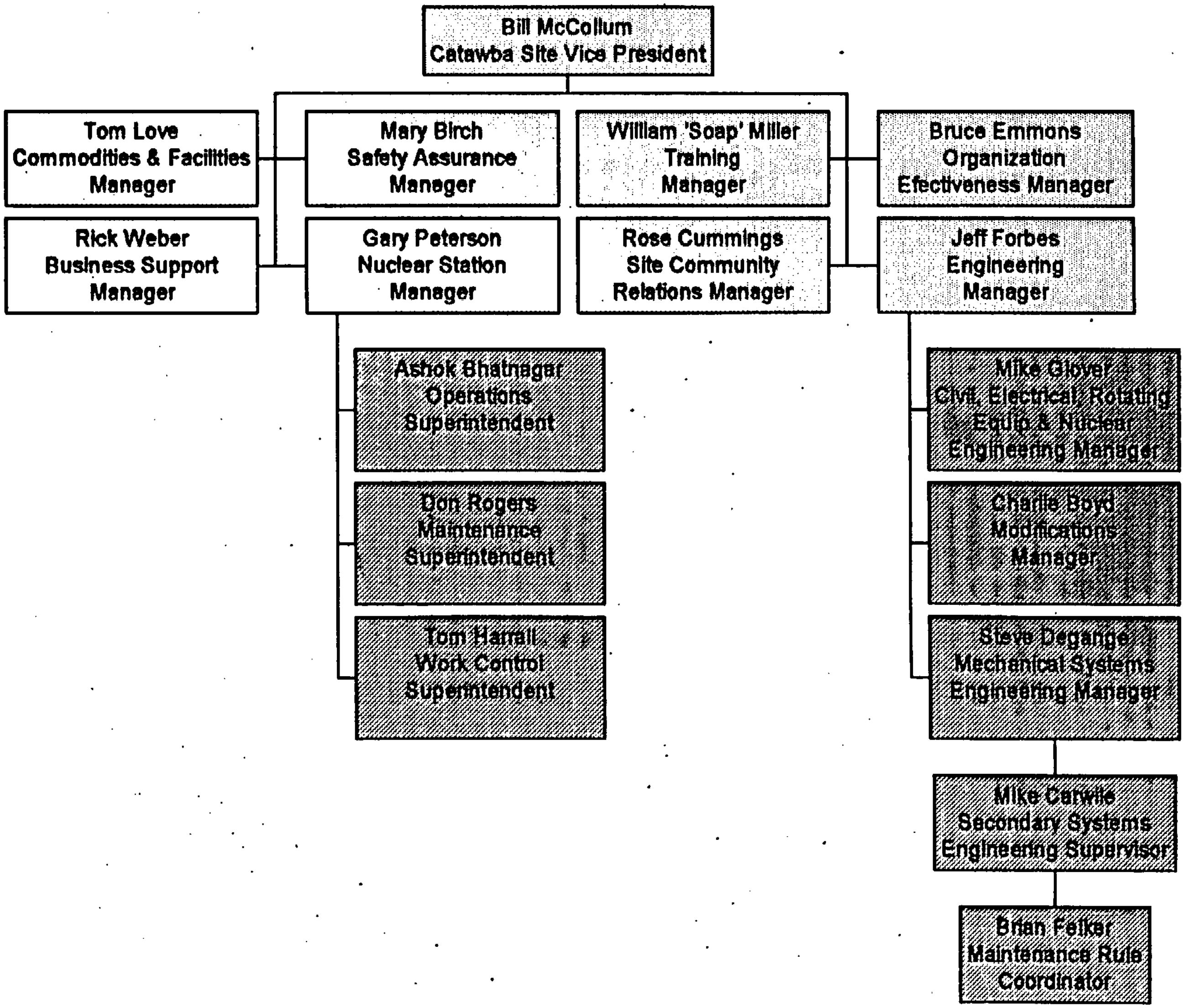
CATAWBA NUCLEAR STATION
MAINTENANCE RULE
FEBRUARY 10, 1997
ENTRANCE PRESENTATION AGENDA

Introduction	Mary Birch
Maintenance Rule Implementation History	Mary Birch
Uniqueness of Catawba	Mary Birch
Maintenance Rule Program	Brian Felker
PRA Interface	Duncan Brewer

ENTRANCE PRESENTATION AGENDA
(Continued)

A1 SSC History	Brian Felker
A3 Portion of the Rule	Brian Felker
Self Assessments and Results	Brian Felker
Site Focus Report	Mike Glover
Summary	Mary Birch

SITE ORGANIZATION STRUCTURE



MAINTENANCE RULE IMPLEMENTATION HISTORY

- Two Phase Implementation
  - Maintenance Rule Project Team
  - Maintenance Rule Working Group
- Project Team Purpose
  - Comply with 10 CFR 50.65 and industry guidance documents (NUMARC 93-01)
  - Develop, implement and document method to continuously assess the performance of each site's critical SSCs
  - Provide a well founded, documented basis for PM activities in support of the Maintenance Rule

MAINTENANCE RULE REQUIREMENTS INCORPORATED INTO EXISTING PROGRAMS

- Problem Investigation Process (PIP)
- Work Management System (WMS)
- Technical Specification Action Item Log (TSAIL)
- System Health Indicators
- Failure Analysis and Trending System (FATs)

PROGRAM DEVELOPMENT

- Joint Development With McGuire
  - Similar Plant Design
  - Increased Resources and Expertise
  - Awareness of Differences Ensured Questioning Attitude
- Developed a Work Place Procedure for the Project phase, which led to current:
  - Nuclear Site Directive 310
  - Engineering Directive Manual 210

IMPLEMENTATION PROGRAM

MAINTENANCE RULE WORKING GROUP

- Mike Carwile
  Engineering Manager
  Sponsor
  - Pam Kowalewski
    Leader
    NGO Mechanical Systems
    - Robert Knoerr
      Maintenance Rule Coordinator
      Oconee
    - Brian Felker
      Maintenance Rule Coordinator
      Catawba
    - Terry Pedersen
      Maintenance Rule Coordinator
      McGuire
    - Duncan Brewer
      NGO Severe Accident Analysis
      PRA Expert
    - Charles Sawyer
      NGO Work Control and
      Human Performance

UNIQUENESS OF CATAWBA

- Two Unit Westinghouse 4 Loop Ice Condenser Plant (3411 MW per Unit)
- Forced Draft Cooling Towers
- New Unit 1 Steam Generators
- Standby Shutdown Facility
- Corrective Action Program (Problem Investigation Process, PIP)

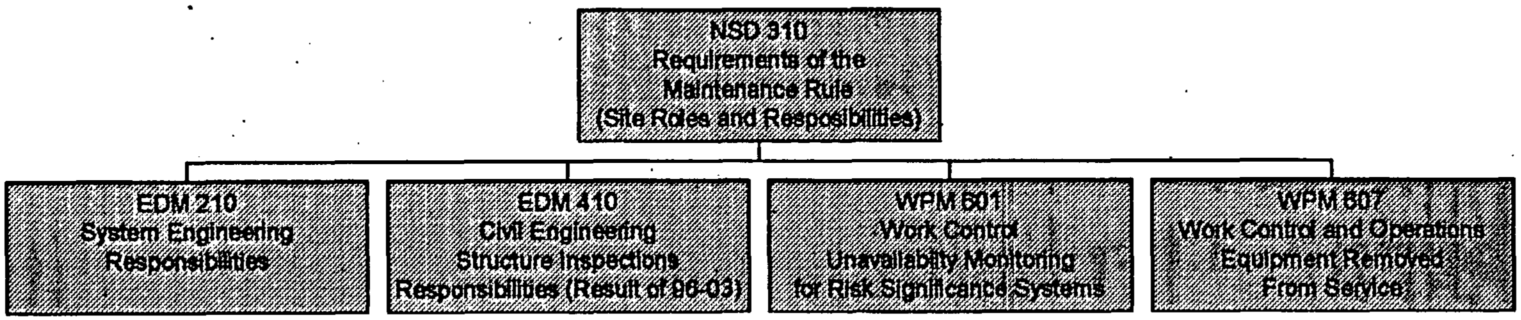
Brian Felker

Site Maintenance Rule
Coordinator

MAINTENANCE RULE PROGRAM

- Administrative Procedures
- Maintenance Rule Process
- SSC Breakdown
- Performance Criteria

ADMINISTRATIVE PROCEDURES



ADMINISTRATIVE PROCEDURES

- Written to NUMARC 93-01, Revision 2 Requirements

- Exceptions to NUMARC 93-01
  - Number of Reactor Trips per Cycle replaces Unplanned Reactor Trips per 7000 Hours
  - Forced Outage Rate replaces Unplanned Capability Loss Factor
  - Safety System Actuations are defined as Unplanned Engineered Safety Features Actuations Reportable by 10 CFR 50.72 and 10 CFR 50.73

MAINTENANCE RULE PROCESS

<u>System Engineers</u>
•Monitoring System Performance
•A1 SSC Corrective Actions

<u>Work Control</u>
•Scheduling Equipment
Out of Service - PRA Risk Matrix

<u>Operations</u>
•Authorization of Maintenance -
PRA Risk Matrix

<u>Safety Review Group</u>
•PIP Screening for Maintenance
Rule Functional Failures

<u>Operating Experience Assessment Group</u>
•Evaluation of Industry Events

Maintenance Rule Coordinator

MAINTENANCE RULE SSCs AND PERFORMANCE CRITERIA

- SSC Breakdown
- Expert Panel
  - Review Systems
  - Determine Risk Significance (R/S)
  - Establish Performance Criteria
  - Develop PRA Risk Matrix
- Performance Criteria
  - Plant Level Performance Criteria
  - System Level Performance Criteria
  - Condition Monitoring for Structures

MAINTENANCE RULE
SSC BREAKDOWN

Total Systems	235
Systems in the Maintenance Rule	143
Risk Significant Systems	42
Risk Significant PRA Risk Matrix Systems	25
Total Structures / Components	79
Structures /Components in the Maintenance Rule	36
Risk Significant Structures	4
Total Maintenance Rule SSCs	179

MAINTENANCE RULE DATABASE

- One source document for Maintenance Rule Data
- Accessible to Engineering Personnel
- Easy to write queries to obtain desired information
- Controlled by Maintenance Rule Coordinator

PLANT LEVEL PERFORMANCE CRITERIA

Type of Measure	Acceptable Performance Criteria (per Unit per Fuel Cycle Due to Maintenance Preventable Causes)	Applies To
Forced Outage Rate	< 8%	All Maintenance Rule SSCs
Reactor Trips	No More Than 1	All Maintenance Rule SSCs
Safety System Actuations	No More Than 1	All Maintenance Rule SSCs
Loss of DHR Events	None Are Allowed	All Maintenance Rule SSCs
Repetitive MPFFs *	None Are Allowed	All Maintenance Rule SSCs

* Repetitive MPFFs Can Cross Unit Boundaries Over a Period of 24 Months

SYSTEM LEVEL PERFORMANCE CRITERIA

Type of Measure	Acceptable Performance Criteria (per Unit per Fuel Cycle)	Applies To
Unavailability (R/S Systems)	Controlled per WPM601	(Each Specific R/S System Group)
Reliability (R/S Systems)	No More Than 1 MPFF	R/S System
[redacted]		
Reliability (Combined R/S and Non-R/S Functions within the System; or Each Non-R/S System)	No More Than 4 MPFFs	All Maintenance Rule SSCs

PERFORMANCE CRITERIA CONDITION MONITORING FOR STRUCTURES

Classification Category	Acceptable Performance Criteria (per inspection period)	Applies To
Acceptable	Good; Maintenance May Continued As Established	All Maintenance Rule Structures
Acceptable with Deficiencies	No More Than 1 MPFF No Repetitive MPFFs	All Maintenance Rule Structures
Unacceptable	Unacceptable Performance; A1	All Maintenance Rule Structures

Duncan Brewer

Nuclear General Office,
Severe Accident Analysis

CATAWBA'S PRA

- Level 3 - Small Event Tree, Large Fault Tree Methodology
  - Core Damage Frequency
  - Containment Response Analysis
  - Releases to the Public and Associated Health Effects
- PRA considers internal and external events
- PRA Limitations
- Important Systems include KC, RN and SSF

PRA CALCULATIONS USED FOR RISK SIGNIFICANT SSCs

- Risk Achievement Worth (RAW)
- Risk Reduction Worth (RRW)
- Core Damage Cut Sets

PRA USAGE

- Used to Determine Unavailability Performance Criteria

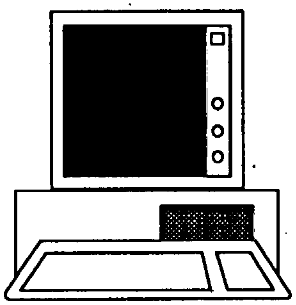
- Input for Developing Risk Significant System Reliability Performance Criteria

INPUTS FOR EXPERT PANEL DECISIONS

Operational Experience

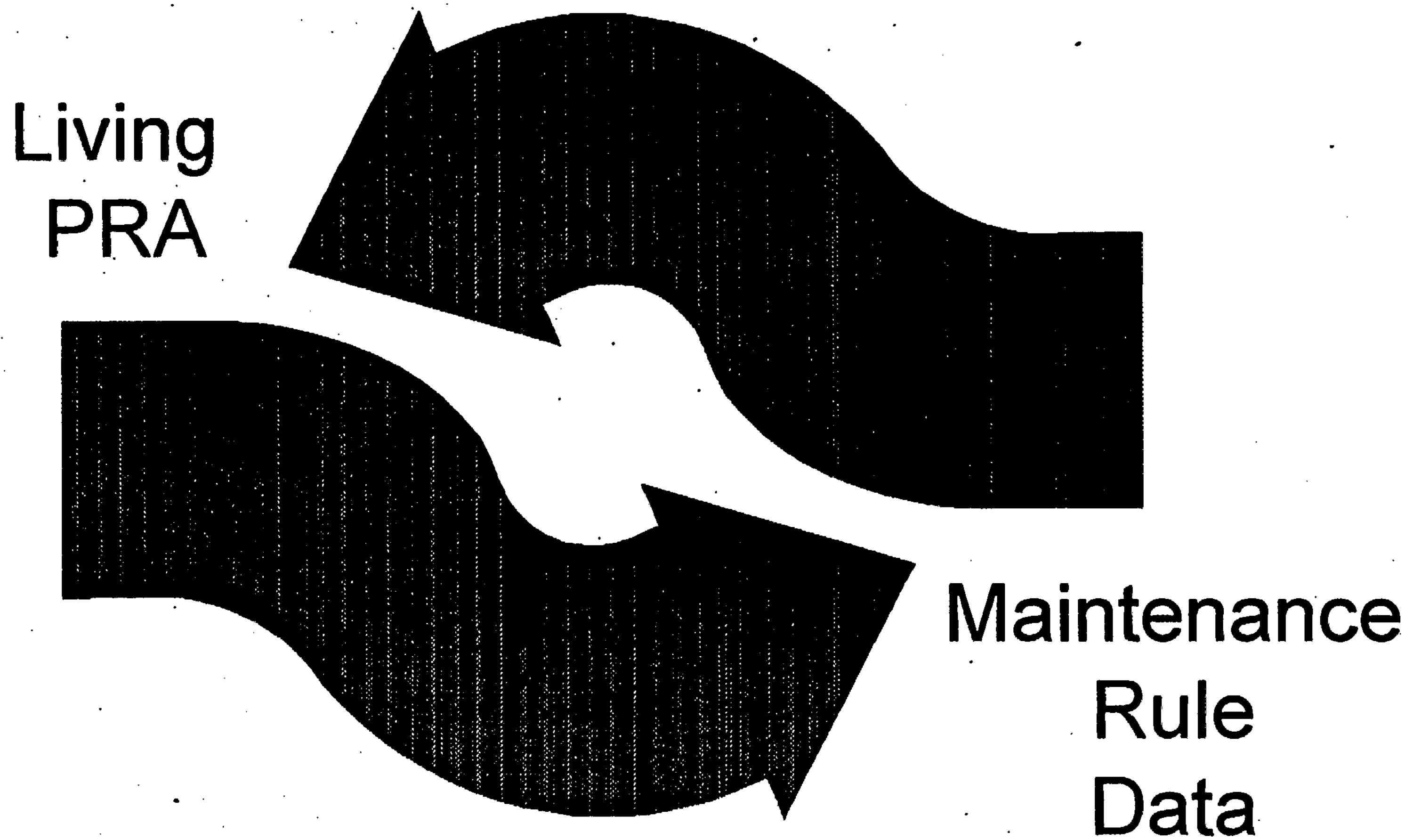
PRA Insights

Risk Significance & Performance Criteria



Deterministic Analysis

FEEDBACK PROCESS



Brian Felker

Site Maintenance Rule
Coordinator

ON-GOING MAINTENANCE RULE ACTIVITIES

- Monthly A1 Evaluation Format
- PRA Risk Matrix
- Periodic Assessments
- Self Assessments

A1 LIST ON JANUARY 10, 1997

Unit	Sys	Risk Signif.	Availability (TSAIL)	Reliability: (MPFFs)	Forced Outage Rate	Rx Trips	ESF Actuations	Loss of DHR	Reliability: Adverse Trend	Repetitive MPFFs
		As Determined by Expert Pnl using PRA	R/S Only: hours per cycle	R/S Only: # > 1 per cycle	Plant Lvl: Total SSC Hrs > 8 % of Cycle EFPDs	Plant Lvl: Combined SSCs # > 1 per cycle	Plant Lvl: Combined SSCs # > 1 per cycle	Plant lvl: Any SSC contributing to # > 0 per cycle	Plant Lvl: Any Non R/S SSC > 4 MPFFs	Plant Lvl: All SSCs # > 0 (over last 24 months)
0	VC	No	N/A	N/A	No	No	No	No	No	Yes
0	YC	No	N/A	N/A	No	No	No	No	No	Yes
1	ND	Yes	No	A1:2MPFFs	No	No	No	No	N/A	No
1	RN	Yes	No	No	No	No	No	No	N/A	Yes
1	VA	No	No	No	No	No	No	No	No	Yes
2	NW	No	N/A	N/A	No	No	No	No	No	Yes
2	RN	Yes	No	A1:2MPFFs	No	No	No	No	N/A	Yes
2	SM	Yes	No	No: 1MPFF	No	Yes	No	No	N/A	No
2	VE	No	N/A	N/A	No	No	No	No	No	Yes
2	WL*	Yes	No	No	No	No	No	No	N/A	Yes

WPM 607 Attach. 607.6.8 CNS PRA Matrix (Rev. 3, 02/03/97)			**Catawba Unit #**							**Risk Assessment Matrix**							Prepared By:					
CAUTION:	This Matrix Does NOT Replace the Technical Specifications.		Date/Time: From:										Until:									
	Tech specs should be reviewed prior to using the matrix.		Electrical					SG Cooling		Cooling Water		Rctr Coolant		ECCS				Containment				SSF
	Matrix applies Modes 1, 2, and 3		SYD	EDG	EPC	SAT	RC	CAmp	CAtp	KC	RN	NCb	NCp	ND	NI	NV	FWST	CNTh	CNTi	ICE	NS	SSF
Electrical	230 kV Switchyard Systems (Note 1)	SYD	■	~~PRA~~	~~PRA~~	~~PRA~~			PRA	~~PRA~~	~~PRA~~											PRA
	Emergency Diesel Generator System (Note 2)	EDG	~~PRA~~	■	~~PRA~~	~~PRA~~	PRA		~~PRA~~								~~PRA~~					~~PRA~~
	4.16 kV Essential Power (Note 2)	EPC	~~PRA~~	~~PRA~~	■	~~PRA~~	PRA		~~PRA~~			PRA	PRA				~~PRA~~					~~PRA~~
	Power to 4160 VAC Standby Transformer From Other Unit	SAT	~~PRA~~	~~PRA~~	~~PRA~~	■																
	RC System Isolation Valves (Note 1)	RC		PRA	PRA		■		PRA		PRA											PRA
SG Cooling	CA System Motor Driven Pump (Note 2)	CAmp						■	~~PRA~~				~~PRA~~	PRA	PRA	~~PRA~~	~~PRA~~					
	CA Turbine Driven Pump	CAtp	PRA	~~PRA~~	~~PRA~~		PRA	~~PRA~~	■	~~PRA~~	~~PRA~~		~~PRA~~	PRA	PRA	~~PRA~~	~~PRA~~					
Cooling Water	Component Cooling System (Note 2)	KC	~~PRA~~						~~PRA~~	■		PRA	PRA				~~PRA~~					~~PRA~~
	RN System (Note 1) (Note 2)	RN	~~PRA~~				PRA		~~PRA~~		■	PRA	PRA				~~PRA~~					~~PRA~~
Reactor Coolant	NC Interfacing System Pressure Boundary	NCb			PRA					PRA	PRA	■	PRA	PRA	PRA	PRA	~~PRA~~					
	NC Pressure Control (Less than 1 Nitrogen Backed PORV per Train Available)	NCp			PRA			~~PRA~~	~~PRA~~	PRA	PRA	PRA	■	PRA	PRA	PRA						
ECCS	ND System (Note 2)	ND						PRA	PRA			PRA	PRA	■	PRA	PRA					PRA	
	NI System (Note 2)	NI						PRA	PRA			PRA	PRA	PRA	■	~~PRA~~						
	NV System (Note 2)	NV						~~PRA~~	~~PRA~~			PRA	PRA	PRA	~~PRA~~	■						PRA
	Refueling Water Storage Tank	FWST		~~PRA~~	~~PRA~~			~~PRA~~	~~PRA~~	~~PRA~~	~~PRA~~	~~PRA~~					■	~~PRA~~	~~PRA~~	~~PRA~~		
Containment	Containment Hydrogen Control Functions (Note 2)	CNTh															~~PRA~~	■	PRA	PRA	PRA	
	Containment Isolation Functions	CNTi															~~PRA~~	PRA	■	PRA	PRA	
	Ice Condenser / Divider Barrier Seal (Note 2)	ICE															~~PRA~~	PRA	PRA	■	~~PRA~~	
	Containment Spray System (Note 2)	NS												PRA				PRA	PRA	~~PRA~~	■	
SSF	Standby Shutdown Systems (Note 1)	SSF	PRA	~~PRA~~	~~PRA~~		PRA			~~PRA~~	~~PRA~~					PRA						■

Note 1: May affect the Matrix for both units.

Note 2: This system or function may be affected by a support system being inoperable. If the system is still functionally avalible, DO NOT highlight it on the Matrix. If the system is unable to perform its Maintenance Rule Risk Significant function, then DO highlight it on the matrix. Further guidnace is provided in WPM 607 Sections 607.5.5 and 607.5.6.

■ Same System

~~PRA~~ PRA Not Allowed

PRA PRA Interaction (2 or More Not Allowed in Same Row or Column)

PERIODIC ASSESSMENTS

- Historical Assessment
  - 3 Year Historical Data Review (January 1, 1993 through December 31, 1995)
  - Established Initial A1 List of 13 Systems
  - Divided into two 18 month cycles

- Unit 1 Periodic Assessment
  - Cycle 9 (March 22, 1995 - October 4, 1996)
  - Addressed 5 A1 Systems

SELF ASSESSMENTS

- NEI Assist Visit (March 1995)
- Site Assessment (May 1996)
- Site Assessment (January 1997)

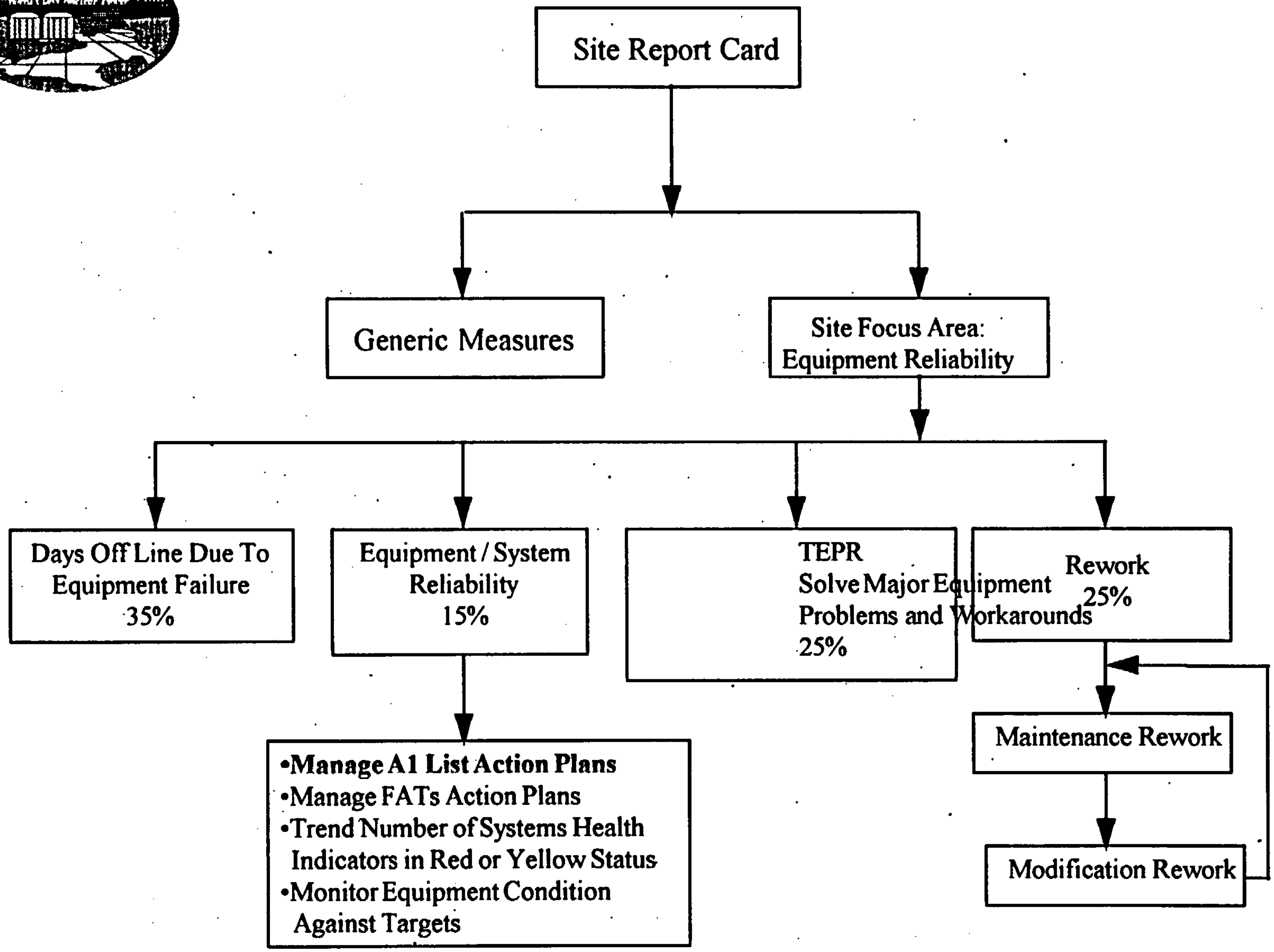
- Strengths Identified:
  - PRA Matrix Development
  - Joint Expert Panel with McGuire

- Significant Challenges for Improvement:
  - Training for Site Personnel
  - Numerous Repetitive MPFFs

Mike Glover

Civil, Electrical Systems,
Rotating Equipment &
Nuclear Engineering Manager

MONTHLY SITE FOCUS REPORT



Mary Birch

Safety Assurance Manager

FUTURE

- Trending of Number of A(1) SSCs in Site Focus Reports
- Evolving and Learning Process
  - Self Correcting Rule
  - Future Process Improvements are Expected
    - PRA Updates
    - PRA for Shutdown Modes

DUKE POWER COMPANY
CATAWBA NUCLEAR STATION

POSITION ON OPERATOR INVOLVEMENT IN MAINTENANCE ACTIVITIES

Duke Power has implemented its Maintenance Rule program to comply with 10 CFR Part 50.65, Regulatory Guide 1.160 and industry guidance (NUMARC 93-01). Our position that operator activities are not covered by the regulation is based on our understanding of the regulation as discussed in NUMARC (and its subsequent organization, NEI) meetings with the NRC and as documented in Regulatory Guide 1.160, NUREG 1526, and in the NUMARC questions and answers.

10 CFR 50.65 is a performance based regulation. In implementation, NUMARC has worked closely with the NRC to ensure consistent implementation of this regulation.

In the Final Commission statement on Maintenance of Nuclear Power Plants and in the NUMARC document, the definition of *maintenance* is expanded to be

"... the aggregate of those functions required to preserve or restore the safety, reliability, and availability of plant structures, systems, and components. Maintenance includes not only activities traditionally associated with identifying and correcting actual or potential degraded conditions, i.e., repair, surveillance, diagnostic examinations, and preventive measures; but extends to all supporting functions for the conduct of these activities. These functions are listed below ...

Activities Which Form the Basis of a Maintenance Program:

An adequate program should consider:

- Technology in the areas of
    - Corrective maintenance
    - Preventive maintenance
    - Predictive maintenance
    - Surveillance:
- Engineering support and plant modifications;
- Quality assurance and quality control;
- Equipment history and trending;
- Maintenance records;
- Management of parts, tools, and facilities;
- Procedures;
- Post-maintenance testing and return-to-service activities;
- Measures of overall program effectiveness;
- Maintenance management and organization in the areas of
    - Planning,
    - Scheduling,
    - Staffing,

  - Shift coverage,
  - Resource allocation;
- Control of contracted maintenance services;
- Radiological exposure control (ALARA);
- Personnel qualification and training;
- Internal communications between the maintenance organization and plant operations and support group;
- Communications between plant and corporate management and the maintenance organization."

This definition broadened the traditional definition of maintenance and NUMARC (NEI) worked closely with the NRC to ensure understanding of this definition. Operator actions and their impact on maintenance were discussed in NRC and utility meetings. This interaction is documented in Section 9.4.5 of NUMARC 93-01 in Table *Examples that are Not MPFFs* and in a NUMARC questions and answers document which NRC reviewed and endorsed before distribution within the industry.

In Section 9.4.5 of NUMARC 93-01 in Table *Examples that are Not MPFFs*, bullet 4 states that operational errors are not to be considered MPFFs. Specific examples from the questions and answers document from the 1993 Maintenance Rule Workshop clarify the statement in this bullet. Refer to questions 5, 15, 28, 29, 30, 31, 33, 35, 60, 63, and 65.

Duke Power has implemented its program to comply with 10 CFR Part 50.65, Regulatory Guide 1.160, and industry guidance (NUMARC 93-01).

ATTACHMENT 3

Follow up to NRC Proposed Violation on the CNS Maintenance Rule Program "Plant Level Performance Criteria was viewed as inadequate"

The (NRC) inspection team found four examples where equipment failures resulted in load reductions and the failures were not screened for MR functional failures. Duke monitors only forced outage rate and not unplanned capability loss factor for the plant level performance criteria. Forced outage rate was questioned by the NRC as an acceptable reliability performance criteria. To address this concern, two issues need to be discussed:

1. Are Functional Failures addressed at the proper system, train, or component level, leading to proper MPFF evaluations or impact on Plant Level Performance Criteria ?

2. Is the use of Forced Outage Rate, which was taken as an Exception to NUMARC 93-01 an inadequate measure of a Plant Level Performance Criteria?

Are Functional Failures addressed at the proper system, train, or component level, leading to proper MPFF evaluations or impact on Plant Level Performance Criteria?

The Duke Power Maintenance Rule Program monitors system health based on system functions. Maintenance Rule system functions are defined by the scoping criteria and the Design Basis functions of the system. For the category of normally operating, Non-Risk significant, Non-Safety Related system functions (the category of the four examples cited), the Maintenance Rule Program evaluates equipment failures at the system level. The four equipment failures in question were not Maintenance Rule System Failures. In each case, the equipment failure did not result in the loss of function. The systems, Unit Main Power Control and the 24 KV Unit Main Power, performed their functions as designed. The systems were designed to respond appropriately to runbacks.

Therefore, the four events listed would not be recognized as Maintenance Rule Functional Failures. Further, for these normally operating, Non-Risk Significant, Non-Safety Related systems, the equipment failures are also not Maintenance Preventable Functional Failures. Forced Outage Rate was not intended to capture these events since the system functions were not lost.

Is the use of Forced Outage Rate, which was taken as an Exception to NUMARC 93-01 an inadequate measure of a Plant Level Performance Criteria?

The use of Forced Outage Rate (FOR) is an Exception to NUMARC 93-01 as identified in company administrative procedures. This program exception was presented during the NRC Entrance Presentation of the Maintenance Rule Inspection on February 10, 1997. The decision to use Forced Outage Rate was based on the company business plan and site goals. Forced Outage Rate is one criterion which is used collectively with other Plant

Level Performance Criteria to evaluate system health. Plant Level Performance Criteria include measures for SCRAMS, Safety System Actuations, Loss of Residual Heat Removal Events, Repetitive MPFFs and Forced Outage Rate (FOR). Forced Outage Rate was also selected by Duke Power as the criterion to recognize inadequate performance at a threshold prior to SCRAMs or SSAs.

In support of this position:

Forced Outage Rate (as defined in NUREG-1272-V3-NI, section 2) is defined as "the quotient of the number of forced outage hours in the selected period divided by the sum of the unit service hours and the forced outage hours. Forced outages are defined as outages required to be initiated by the end of the weekend following the discovery of an off-normal condition. The trends of a forced outage rate can provide a perspective on overall plant performance." Forced Outage Rate is, in actuality, a subset of Unplanned Capability Loss Factor.

Unplanned Capability Loss Factor (UCLF) is defined as the ratio of the unplanned energy losses during a given period of time, to the reference energy generation, expressed as a percentage(WANO Performance Indicator Program, Utility Data Coordinator Reference Notebook, INPO 96-003). Unplanned energy loss is energy that was not produced during the period because of unplanned shutdowns, outage extensions, or unplanned load reductions due to causes under plant management control. Unplanned is defined as not scheduled at least four weeks in advance.

Both Forced Outage Rate and Unplanned Capability Loss Factor are reliability measures. Use of a reliability measure for measuring system health is supported by the Statement of Consideration for the Maintenance Rule. From the Statement of Consideration for the Maintenance Rule "The purpose of paragraph (a)(2) of the rule is to provide an alternate approach for those SSCs where it is not necessary to establish the monitoring regime required by (a)(1)...The utility is encouraged to consider the use of reliability-based methods for developing the preventive maintenance programs covered under this section of the rule....." The Statement of Consideration continues to clarify how performance criteria should be developed and integrated with existing programs. "Rather than monitoring the many SSCs which could cause plant scrams, the licensee may choose to establish a performance indicator for unplanned automatic scrams and, where scrams due to equipment failures have been problematic or where such scrams are anticipated, choose to monitor those initiators most likely to cause scrams. It is not intended that this monitoring requirement duplicate activities currently being conducted, such as technical specifications surveillance testing, which could be integrated with and provide the basis for, the requisite level of monitoring. Consistent with the underlying purposes of the rule, maximum flexibility should be offered to licensees in establishing and modifying their monitoring activities." Duke Power used this guidance on flexibility to adopt Forced Outage Rate as a reliability performance criterion.

In Summary, we monitor normally operating, Non-Risk Significant System Functions with cumulative Plant Level Performance Criteria. These criteria include measures for SCRAMS, Safety System Actuations, Loss of Residual Heat Removal Events, Repetitive MPFFs and Forced Outage Rate. The selection of Forced Outage Rate has been targeted at system failures that require a planned or unplanned force outage due to maintenance to reclassify the system to a(1) of 10 CFR Part 50.65.. Therefore, we comply with the intent of the Maintenance Rule. However, from the results of the NRC Maintenance Rule Inspection, PIP # 0-C97-0401 has been written to evaluate the use of Unplanned Capability Loss Factor as a Plant Level Performance Criteria.

The Events identified by the NRC and referenced above are listed below. These descriptions have been taken from the site corrective action program tracking system (PIP, some editing has been used for reader clarity):

PIP: 2-C-94-0077: Unit Main Power Control System (ERE) Date: 1/12/94

This event was evaluated during the Historical Review. Lessons learned through industry workshops and the DPC May/June 1996 Assessment have indicated that our events associated with Non Risk Significant, Operating System Functions were evaluated overly conservative during the 1/1/93-7/1/96 period, when the system function had not failed. The NUMARC 93-01 Guidelines provides direction (Section 9.3.2) on Functional Failure guidance for Operating, Non-Risk Significant systems such that loss of the system function should consider the scoping criteria and the design basis of the system, including its response to equipment failures. Additionally, since the ERE system performance was recognized as adequate for monitoring under A2, the conservatism of the Historical Review was not updated following the May/June Assessment.

The main turbine ran back to 56% power when the A main generator breaker opened. The cause of the breaker opening appears to be due to the arching over to a micro switch on the generator breaker safety switch. This made it appear that the breaker had been taken to the "safe" position, which trips the breaker. Main vacuum decreased subsequent to the runback and at ~0947, the turbine tripped on low vacuum.

The runback was successful. The Turbine runback is attributed to a degraded microswitch on 2A Generator Side Motor Operated Disconnect (2AG Motor Operated Disconnect) of 2A Generator Breaker. Initial inspection of the 2AG Motor Operated Disconnect found that the microswitch was corroded and burned. A significant amount of corrosion had formed on the contacts of the microswitch . This resulted in an arcing across the contacts. This caused a false signal to be sent to the control circuit indicating a position other than "Auto". Subsequently, a trip signal was generated which caused 2A Generator Breaker to open. 2AG Motor Operated Disconnect microswitch was replaced per work order 94003247-01.

The root of the conclusion is that moisture must be present to create problems of corrosion on the microswitch. A detailed inspection of the cabinets by Engineering and SPOC revealed indications of condensation in the cabinets even though they all have heaters that function properly. There were no signs of cabinet top leakage. The conclusion reached in this inspection is that water was accumulating on the cabinet pad and then running in the cabinet in openings around the base of the cabinet. In some cases, the opening at the base ran all the way around the cabinet and essentially left the cabinet open to all outside air moisture on a continuing basis. It was impossible for the heaters to overcome this type of moisture supply. SPOC sealed the base of the cabinets on both units. Subsequent inspections by SPOC and Engineering following rainstorms has revealed no signs of moisture intrusion in the cabinets. This action appears to have cured the moisture supply problem in the cabinets. The cabinet heaters should now be able to maintain a dry environment in the cabinet. With this problem cured, new micro switches installed and regularly inspected, the entire microswitch corrosion problem should be cured.

One additional subsequent action was to develop a procedure which will include specific inspections of the microswitches on a routine basis.

Final Status:

All Corrective Actions have been completed and closed. This event has not reoccurred, therefore the corrective actions taken have been determined appropriate and effective.

Note: The loss of condenser vacuum and subsequent events is tracked under PIP # 2-C-94-0041 under the Heater Bleed Steam "B" (HB) system.

Maintenance Rule Evaluation:

This equipment failure was originally considered a Maintenance Rule Functional Failure. and therefore an MPFF during the Historical review. As stated under the PIP heading, this equipment failure has been reevaluated and is not an MRFF for this normally Operating Non-Risk Significant System.

PIP: 2C94-0999: 24KV Unit Main Power System (EPA) Date: 7/13/94

This event was evaluated during the Historical Review. Lessons learned through industry workshops and the DPC May/June 1996 Assessment have indicated that our events associated with Non Risk Significant, Operating System Functions were evaluated overly conservative during the 1/1/93-7/1/96 period, when the system function had not failed. The NUMARC 93-01 Guidelines provides direction (Section 9.3.2) on Functional Failure guidance for Operating, Non-Risk Significant systems such that loss of the system function should consider the scoping criteria and the design basis of the system, including its response to equipment failures. Additionally, since the EPA system performance was recognized as adequate for monitoring under A2, the conservatism of the Historical Review was not updated following the May/June Assessment.

While unit 2 was at 100% power the 2A Main Generator Power Circuit Breaker tripped causing a runback to approximately 56%. The Power Circuit Breaker trip was caused by 61-1 and 61-2 relay actuation. Discovered that relay 61-1 had failed and that 61-2 relay apparently actuated spuriously.

Held unit at approximately 50% power while problem was investigated. Also checked other 61 relays for unit 1 main generator Power Circuit Breakers and 2B Main generator Power Circuit Breaker to verify they had not failed and no other failures were found.

The cause of this problem is unknown. It is speculated that an actual pole disagreement or significant imbalance of power flow on the 2A main power system actually occurred. There is no documented evidence of this. This speculation is based on the fact that the 61-2 relay was found to be good and that the 61-1 relay was tested as good during 2EOC6 less than 30 days before. The failed 61-1 relay has been sent to the manufacturer for analysis. While it is not believed possible at this time, if its failure could have caused this transient (by also picking up 61-2), this pip will be revised to so reflect. This analysis will be addressed in a CAC. It needs to be noted that no other relays actuated in this event. Since the differential relays did not actuate, problems with the CT"s themselves are eliminated. An investigation and checkout of the Generator Power Circuit Breaker also found no apparent problems that may have caused the problem. A slight misalignment or bad contact on any pole of Power Circuit Breaker or Motor Operated Disconnect that allowed the buildup of even 1 ohm of resistance could have caused this problem. This occurrence cannot be proved or dis-proved.

As stated the root cause of the problem is unknown, however some problems and areas needing improvements were found in the investigation. With the unknown root cause, further monitoring of the currents to ensure a consistent balance of the current flows through Power Circuit Breaker will be continued until September 1. This will be performed weekly on both units. Work request will be issued to IAE.

The targets on the 61 relays did not actuate in the event. These relay targets have a coil that must be picked up to drop them. The relay can put this coil on a 2 or .2 amp setting. The 61"s are set on the 2 amp tap. While the circuit is designed to pull 2 amps through this target coil, it will only pull it for an instant and then it clear itself. The instant it pulls the 2 amps is not long enough to activate the target coils and thus they do not fall. These relays, which were originally established at 2 amps at construction, need to have their coils set on the .2 amp tap. This problem may be present on other station relaying and a review is needed to determine the scope of the problem. A work request will be issued to IAE to review the actual relay tap settings on applicable relays and will be followed by an ESE review of those set on the 2 amp tap.

A second problem was the 2/2 logic associated with the pole disagreement relays is able to have one half of the logic satisfied with no indication of this anywhere. Thus a relay failure is undetected. For this particular application some type of correction needs to be made to allow the satisfying of one relay in the circuit to be made known in some fashion to Operations. Other station relaying circuits need to be reviewed by ESE to ensure the same problem is not present.

Another problem noted was the elevated DC voltage applied to the relays. It is not known if the voltage level would have any effect on the relaying at this time. The actual voltage of the DC at the relays needs to be measured and the effects of this on the relays needs to be reviewed with the manufacturer and considered in the failure analysis being performed on the 61-1 relay.

During this event the oscillograph did not fire to record the transient. This equipment is extremely dated and is obsolete. ESE should evaluate the replacement of these antiquated recorders with digital fault recorders. Such a digital fault recorder would most likely have recorded the information needed to determine root cause in this incident. These recorders are manufactured to record pre-fault information thus catching the initiating portions of a transient. The need for certain root cause conclusions on plant events requires adequate equipment and information to make such a determination.

The final enhancement that was noted was in the area of Generator Power Circuit Breaker checkouts. There are known internal leaks on certain Power Circuit Breakers. Past practice has been to monitor these leaks until they became bad enough to fix. Bad enough was excessive operation of the air compressors which also is not specifically defined. ESE needs to review manufacturer information to determine if there is a specified leak rate on these Power Circuit Breakers and determine if there is any testing that can be performed such that needed major maintenance can be determined to repair these leaks.

The final noted problem was with the units runback in that generator megawatts was too high for one train of main power and Operations had to manually reduce megawatts to avoid a Zone B lockout. The Turbine Control System runs back to a set point based on stage pressure. It performed this with no errors. The problem with high megawatt out put following a run back may be that the stage pressure setpoint is too high. SES should review this set point to determine if it is at the proper pressure for a runback with no need for manual power reduction.

Final Status:

All Corrective Actions have been completed and closed. This event has not reoccurred, therefore the corrective actions taken have been determined appropriate and effective.

Maintenance Rule Evaluation:

This event, evaluated during the Historical review, was originally identified as an Maintenance Rule Functional Failure. It was not identified to be an MPFF due to the unclear cause of the event. With the unknown root cause, further monitoring of the currents to ensure a consistent balance of the current flows through each Power Circuit Breaker were to be continued to assist in a root cause should the event reoccur. As stated under the PIP heading, this equipment failure has been reevaluated and is not an MRFF for this normally operating, non risk significant system.

PIP: 2-C96-1059: 24KV Unit Main Power System (EPA) Date: 5/6/96

This event was evaluated during the Historical Review. Lessons learned through industry workshops and the DPC May/June 1996 Assessment have indicated that our events associated with Non Risk Significant, Operating System Functions were evaluated overly conservative during the 1/1/93- 7/1/96 period, when the system function had not failed. The NUMARC 93-01 Guidelines provides direction (Section 9.3.2) on Functional Failure guidance for Operating, Non-Risk Significant systems such that loss of the system function should consider the scoping criteria and the design basis of the system, including its response to equipment failures. Additionally, since the EPA system performance was recognized as adequate for monitoring under A2, the conservatism of this review was not updated following the May/June Assessment.

Unit 2 ran back to 50% power when the 2B Generator Power Circuit Breaker opened. The breaker opened immediately on the opened of breaker 8-13 in MSU 2B for the cooling groups. Found relay timer associated with cooler group loss of power smoked. A FIP was initiated.

The cause of the trip of the Generator Power Circuit Breaker 2B trip was due to a Struthers Dunn 219BBXP relay being picked up on most every operation of the 8-13 breaker for the emergency power supply to the group 2 cooling bank on 2B MSU. There was no signal being sent to the relay to pick up through any normal circuitry. The problem is likely an induced pickup of the relay or vibration. Replacement of the relay made the problem disappear and it reappeared when the relay was put back into the circuit. The relay has been sent to the General Office (Rick Dover) for failure analysis. The location of the relay was directly under a Cutler Hammer relay that properly actuated on each operation of the 8-13 breaker.

At this time, an adequate level of testing has been performed in an effort to determine the root cause of the relay failure. The tests have not been able to repeat the failure Motor Operated Disconnect that was seen in the field with the suspect relay. The suspect relay was replaced and no other problems have been observed with this relay. No additional testing is required at this time. If plant or relay trends show additional events of this kind, vendor testing and analysis will likely be used.

The Struthers Dunn relay was device XC in 2EB1. This relay is actuated by a three minute timer in the MSU cooling group control circuitry. The three minute timer is actuated when both cooling groups experience a loss of power. There was never any actuation of the three minute timer and it never sent any type of signal to the Struthers Dunn relay. The XC relay, when actuated, provides a direct trip signal to the trip coil #2 of all three poles on the generator Power Circuit Breaker.

Final Status:

All Corrective Actions have been completed and closed or are well underway as appropriately scheduled. This event has not reoccurred, therefore the Corrective Actions taken have been determined appropriate and effective.

Maintenance Rule Evaluation:

This event was originally identified as an Maintenance Rule Functional Failure. It was not identified to be an MPFF. There was no manufacturer recommended replacement schedule for these relays. It was determined that this event was a spurious trip. As stated under the PIP heading, this equipment failure has been reevaluated and is not an MRFF for this normally operating non risk significant system.

PIP: 1-C-96-2880 24KV Unit Main Power System (EPA) Date: 10/27/96

Notified by Operations of Main Transformer 1A Operator Aided Computer (OAC) trouble alarm. The reflash monitor panel alarm indicated a "gas detection alarm". When the operator acknowledged the reflash monitor alarm, he noticed the second fan from the top on cooling group #2 had come loose from the shaft.

After troubleshooting, it was indicated that there was indeed gas of an undetermined composition and origin in the transformer. A request was made for Power Delivery personnel to assist in troubleshooting and transformer oil sampling. A second Main Transformer 1A OAC trouble alarm was received which was "Low Oil Level" at the reflash monitor panel. Discussions were held with the Duty Station Manager and the Station Manager and the decision made to deenergize cooling group #2 and investigate for potential oil leaks and/or sources of gas inleakage.

When the cooling group #2 was secured, an extremely severe oil leak developed at the return oil pipe from the cooling group #2 to the transformer. This pipe is located at the top of the cooling group #2 and the main transformer. The decision was made to enter AP/1/A/5500/09, Rapid Downpower, reduce power to 50% and secure Main Transformer 1A. Operations was able to isolate the oil leak.

The failure of the fan is the cause of the event. Vibration of the cooler #2 fan #2 when failing caused a weld to crack at the top of the cooler. This allowed air into the transformer due to the suction of the pump and gave initial gas alarm. It also allowed oil out of the transformer when the pump was secured. The high air content and low oil level required shutdown of the transformer.

The severe vibration associated with the fan failure created the crack in the weld. Once cracked the suction of the pump on that cooler pulled air into the transformer. In the effort to isolate the cooler the pump and fans were shut off. This left a positive relative pressure to atmosphere and oil was pumped out by the remaining pumps.

Final Status:

All Corrective Actions have been completed and closed or are well underway as appropriately scheduled. This event has not reoccurred, therefore the Corrective Actions taken have been determined appropriate and effective.

Maintenance Rule Evaluation:

This event was not considered an MRFF. The system function (EPA.2) was not lost. Although an equipment failure initiated the event, EPA maintained generated power to the switchyard through B zone. Simultaneously the auto swap functions (as designed) realigned the supply power at the essential level and unit auxiliary level.